momentum

DELPHI ENERGY CORP. ANNUAL REPORT 2009

its not merely motion, but the power residing in that moving object...

It's mass.
HIGH QUALITY ASSETS

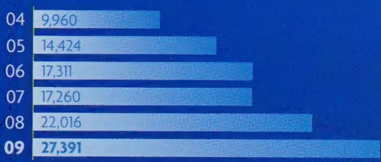
It's velocity.
WHERE WE'VE BEEN AND WHERE WE'RE GOING

Delphi has momentum.

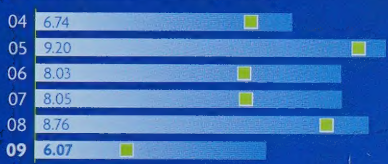
Delphi has positioned itself to deliver long term sustainable growth. The Company's undeveloped land position increased 37 percent to 172,210 net acres during 2009. The high quality concentrated producing assets and undeveloped land base focused at Hythe, Bigstone and Wapiti/Gold Creek in North West Alberta continue to deliver predictable economic production and reserve growth.

PRODUCTION (boe/d)

P+P RESERVES (mboe)



REALIZED GAS PRICE ($/mcf)
BENCHMARK AECO ($/mcf)



CASH NETBACKS ($/boe)

CASH FLOW ($thousands)

UNDEVELOPED LAND (net acres)

CORPORATE PROFILE

Delphi Energy Corp. is a public company primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations are principally concentrated in North West Alberta. The Company has four primary core areas in the deep basin of North West Alberta at Bigstone, Hythe, Wapiti/Gold Creek and Tower Creek, which comprise over 76 percent of 2009 production.

The Company is focused on conventional multi-zone vertical well opportunities blended with complementary horizontal well resource plays to generate a balance between the superior flowing barrel efficiency of conventional drilling with the more attractive finding and development costs of resource plays.

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2009 HIGHLIGHTS

	Year Ended December 31	
	2009	2008
FINANCIAL HIGHLIGHTS		
($ thousands except per boe and per share amounts)		
Gross petroleum and natural gas sales	**98,164**	135,402
Per boe	**39.50**	58.31
Funds from operations	**49,241**	68,657
Per boe	**19.81**	29.57
Per share – Basic	**0.59**	0.94
– Diluted	**0.59**	0.93
Net earnings (loss)	**(8,029)**	5,094
Per boe	**(3.23)**	2.19
Per share – Basic	**(0.10)**	0.07
– Diluted	**(0.10)**	0.07
Capital invested	**33,946**	76,779
Dispositions of properties	**(20,718)**	(8,450)
Net capital invested	**13,228**	68,329
Acquisitions [1]	**46,887**	38,120
Total capital invested	**60,115**	106,449
Debt plus working capital deficit	**92,538**	109,237
Total assets	**361,698**	364,538
Shares outstanding (thousands)		
Basic	**101,166**	79,067
Diluted	**108,594**	83,798

(1) includes the costs of the acquisition of Fairmount Energy Inc.

	Year Ended December 31	
	2009	2008
OPERATING HIGHLIGHTS		
Average Daily Production		
Natural gas (mcf/d)	**34,673**	33,236
Percentage of total production	**85%**	87%
Oil and natural gas liquids (bbls/d)	**1,029**	806
Percentage of total production	**15%**	13%
Total (boe/d)	**6,808**	6,345
Realized selling prices		
Natural gas ($/mcf)	**6.07**	8.76
Oil ($/bbl)	**63.87**	89.88
Natural gas liquids ($/bbl)	**48.50**	80.49
Total oil equivalent ($/boe)	**39.50**	58.31
Wells drilled (net)	**7.7**	16.7
Undeveloped land		
Gross acres	**372,896**	315,479
Net acres	**172,210**	125,359
Average working interest (%)	**46%**	40%
Proved plus probable reserves (P+P)		
Natural gas (mmcf)	**140,191**	116,809
Oil and natural gas liquids (mbbls)	**4,025**	2,548
Total oil equivalent (mboe)	**27,391**	22,016
Finding and development costs (P+P)	**12.02**	20.05
Finding, development and acquisition costs (P+P)	**9.21**	20.70
Reserve life index (P+P)	**11.0**	9.5

Our message to shareholders

DELPHI HAD ANOTHER GOOD YEAR IN 2009 GAINING MOMENTUM FROM A SOLID YEAR OF GROWTH IN 2008. THE COMPANY ACCOMPLISHED ITS GOALS OF DELIVERING OPERATIONAL GROWTH AGAIN IN 2009 AND ADDING TO ITS INVENTORY OF FUTURE GROWTH PROJECTS WHILE MAINTAINING A ROBUST FINANCIAL POSITION, IN AN ENVIRONMENT WHERE NATURAL GAS PRICES FELL 51 PERCENT AND CRUDE OIL PRICES DROPPED 35 PERCENT FROM 2008 LEVELS. THE COMPANY REMAINS WELL POSITIONED FOR SUSTAINABLE LONG TERM ORGANIC GROWTH IN ANY BUSINESS ENVIRONMENT.

The stabilization of the global economies throughout 2009 was a welcome relief from the despairing recessionary pressures of 2008, resulting in capital markets returning to a more rational state and world oil prices recovering from a low of approximately U.S. $35.00 per barrel in early 2009 to U.S. $80.00 per barrel by the end of 2009. AECO natural gas prices continued to experience downward pressure and extreme volatility in 2009 falling from a high of $11.83 per mcf in 2008 to a low of AECO $2.02 per mcf in September 2009 before recovering to approximately $5.00 per mcf by year-end.

Adapting to a new paradigm of lower natural gas prices for the foreseeable future is one of industry's greater near term challenges. In this new paradigm, technological advances such as multi-stage fracing in horizontal wells are contributing to significant growth in North American unconventional natural gas supply which in turn will be a prelude to significant demand growth as the marginal cost of this new supply gains political and public confidence. The Company's recycle ratio will continue to be a reliable measure of economic success with cost structure, commodity mix, and reserve life being key drivers in yielding higher netbacks and lower onstream capital costs on a per unit basis.

We believe our fundamental strategies will continue to provide the Company with a competitive advantage as we adjust to this new paradigm.

- We continue to focus the technical and operational expertise of our staff on synergistic play-types within our core areas mitigating exploration and operational risks while driving down capital on-stream costs and maximizing reserve additions.
- The continued application of technological advancements throughout 2009 and beyond is unlocking an even larger scale low-cost growth platform for the Company than previously envisioned.
- We maintain direct control over our core assets, operating over 85 percent of our production and 95 percent of our capital programs.

- The large contiguous land positions complete with strategic infrastructure in each of our core areas provides repeatable and scalable project inventory with capital and production cost structure advantages.
- Natural gas price volatility and weakness continues to be successfully mitigated with an active hedging program maintaining a forward-looking 12 to 24 month hedge position.
- Delphi has had immediate success increasing its light oil and natural gas liquids production as a result of greater capital spending towards light oil exploration and development on Company lands within three of our core areas.
- Financial stability and strength has been maintained through the use of internally generated cash flow for capital programs to ensure prudent debt to cash flow and debt to equity ratios.

YEAR IN REVIEW

Financial results in 2009 are highlighted by strong funds flow from operations (cash flow) despite a 51 percent drop in the average AECO natural gas reference pricing to $3.96 per mcf from $8.16 per mcf in 2008. The low natural gas prices in 2009 were mitigated by another year of successful hedging with the Company realizing $6.07 per mcf on its natural gas sales. Hedging gains in 2009 only partially offset the drop in natural gas and crude oil prices over 2008, as total revenue per boe dropped 32 percent. The Company's cost structure improved in 2009 as total cash costs decreased almost 10 percent. Operating costs dropped 12 percent to $9.08 per boe compared to 2008.

Financial flexibility increased again during 2009 for the third consecutive year with debt and working capital falling to 74 percent of available bank facilities at December 31, 2009. Unutilized credit available on the Company's $125.0 million banking facilities increased to $32.5 million at year-end 2009 while the debt to trailing cash flow ratio at December 31, 2009 rose to 1.9:1 from 1.6:1 at December 31, 2008. To facilitate continued growth, the Company expanded its lending group, in 2009, through the syndication of its credit facilities and the addition of a third chartered bank.

Operational results in 2009, like 2008 are highlighted by record production volumes and record reserve growth. Production during 2009 averaged 6,808 boe/d, representing a seven percent increase over 2008. The Company also increased the crude oil and natural gas liquids production mix to 16 percent during the fourth quarter 2009 compared to 14 percent during the first quarter.

During 2009, Delphi completed a net field capital program of $33.9 million, approximately half of the capital invested in 2008. The Company reduced its 2009 field capital program in order to pursue strategic acquisitions in a favourable counter-cyclical environment. The Company achieved 100 percent drilling success on a 10 (7.7 net) well program during 2009 compared

to 96 percent on a larger 23 (16.7 net) well program in 2008. The field capital program was funded entirely from internally generated cash flow from operations, consistent with the Company's strategy.

Delphi had an active acquisitions and divestment (A&D) program in 2009, with net capital of $26.2 million. Within the A&D program, the Company acquired a net 4.6 million boe of total proven and probable reserves at a cost of $5.67 per boe, complete with significant undeveloped land and interests in major gathering system and natural gas processing infrastructure within its core operating areas. Delphi's undeveloped land position which is a measure of its future growth prospect inventory grew 37 percent in 2009 to 172,210 net acres (269 sections) and has grown 92 percent since 2007.

The reserves additions from the field capital and A&D programs replaced production in 2009 by 3.2 times, at top quartile capital efficiency metrics. The Company also increased its reserve life index by 16 percent to 11 years. Total proved reserves increased by 19 percent and total proved plus probable reserves increased by 24 percent over 2008. Over the past two years reserves have increased 58 percent.

Finding and development costs for the 2009 field capital program on proved and probable reserve additions, inclusive of future development capital were $12.02 per boe. All-in finding, development and net acquisition costs on proved plus probable reserve additions for Delphi's total 2009 capital program decreased 56 percent year over year to $9.21 per boe, more than compensating for the 29 percent drop in operating netbacks due to lower commodity prices. The operating netback recycle ratio increased 61 percent to 2.6 times, compared to 2008.

The Company issued 13.2 million common shares and 3.0 million flow-through shares in 2009 for proceeds of $22.9 million to fund its 2009 capital program. At December 31, 2009, the Company's net debt was $92.5 million or $16.7 million less than at December 31, 2008.

We have positioned Delphi to deliver long term sustainable growth in an environment of lower natural gas prices. Our high quality producing assets with Company owned strategic infrastructure focused at Hythe, Wapiti/Gold Creek and Bigstone in North West Alberta continues to deliver predictable economic production and cash flow growth. We believe the low-cost reserve additions achieved in 2009 are repeatable and scalable on our existing large undeveloped and under-developed contiguous land bases within these core areas. Increased light oil and natural gas liquids production is providing a natural hedge against uncertain and volatile natural gas prices. Technological advances such as multi-stage fracing in horizontal wells and gas fracing techniques have been successfully applied to the Doe Creek, Cardium, Dunvegan, Falher, and Bluesky formations resulting in significant inventory growth of both light oil and natural gas projects. The use of these technologies also applies to the Nikanassin formation at Hythe and Wapiti/Gold Creek and the Gething formation at Bigstone providing even more growth potential for the Company.

OUTLOOK

2010 will be an exciting year for Delphi as we execute a much larger field capital program than 2009 focusing on at least two light oil development projects and up to four separate natural gas resource development projects using horizontal drilling and multistage fracing techniques.

We expect to spend an estimated $60 to $65 million in 2010 drilling up to 24 gross wells compared to 10 wells during 2009. The field capital will be directed towards drilling and completion activities in the Bigstone, Hythe and Wapiti/Gold Creek core areas. We anticipate that approximately 50 percent of the wells drilled during 2010 will utilize horizontal drilling and multi-stage fracing technologies with greater than 50 percent of the capital being focused on light oil and liquids-rich natural gas projects. The planned 2010 capital program executed within forecasted cash flow is expected to result in average production volumes of approximately 7,500 to 8,000 boe/d.

We are forecasting moderate improvement in natural gas prices through the second half of 2010 and into 2011. Delphi is assuming 2010 AECO natural gas prices to average between Cdn $5.00 and $6.00 per mcf for budgeting purposes and has successfully mitigated downside commodity price risk with an active natural gas hedging program since 2006. During 2010, the Company has again hedged approximately 54 percent of its natural gas production at an average floor price of $6.24 per mcf which represents a 15 percent premium to the 2010 strip price of $5.40 per mcf.

Bank debt including working capital is estimated to be between $95 million and $100 million at December 31, 2010.

The Company continues to evaluate and pursue strategic property acquisitions complementary to its existing core assets in what we expect to be another year of attractively priced opportunities.

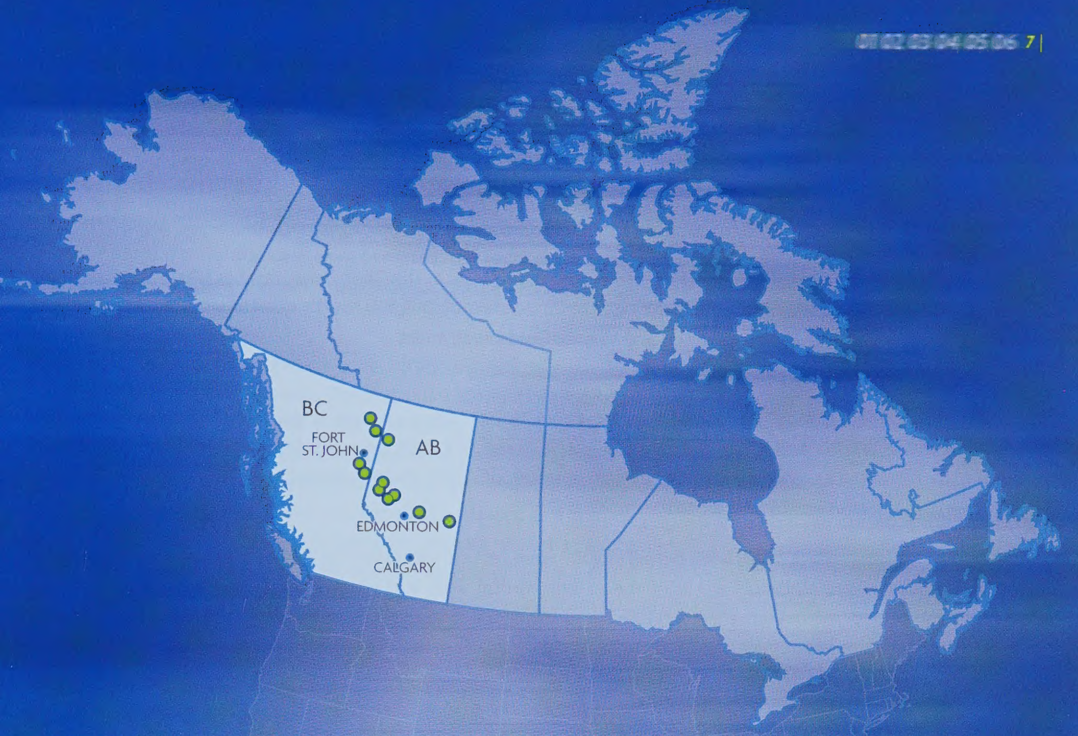
We remain confident in our ability to maintain the momentum created over the past two years and continue to deliver sustainable long term growth in this new paradigm of lower natural gas prices.

On behalf of the Board of Directors and all the employees of Delphi, we would like to thank our shareholders for their continued support as we strive to replicate the successes of 2009.

On behalf of the Board,

David Reid

David J. Reid
President and Chief Executive Officer
March 16, 2010



review of operations

DURING 2009, DELPHI CONTINUED TO EXPAND AND DEVELOP AN ALREADY EXTENSIVE LAND AND NATURAL GAS INFRASTRUCTURE BASE IN THE DEEP BASIN AREA OF NORTH WEST ALBERTA TARGETING PREDICTABLE AND SCALABLE OPPORTUNITIES THAT WILL PROVIDE YEARS OF ECONOMIC GROWTH. THE COMPANY'S SUCCESS IS A DIRECT RESULT OF HAVING A QUALITY ASSET BASE, APPLYING THE LATEST DRILLING AND COMPLETIONS TECHNIQUES AND OPTIMIZING OPERATING MARGINS THROUGH COMPANY OWNED INFRASTRUCTURE.

One of Delphi's primary objectives is to generate sustainable, economic growth in a low commodity price environment. A key component of our business model will be a targeted recycle ratio (netback per boe divided by the finding and development cost per boe) of between 1.5 and 2.0 which can be achieved by driving down finding and development costs while at the same time maximizing netbacks.

Delphi's core area in the Deep Basin of North West Alberta is characterized by multi-zone potential with large in-place volumes of hydrocarbons that require multiple wells per section to fully exploit. On the majority of Delphi's land base, the Company has the ability to drill up to four gas wells per 640 acre spacing unit and commingle the productive intervals encountered in the wellbore which contributes to a repeatable and scalable inventory of low risk, development opportunities. The combination of multi-zone potential, large in-place volumes of hydrocarbons and a large inventory of development opportunities are key in delivering low finding and development costs. The Company incorporates the latest in drilling and completion techniques; specifically horizontal drilling, multi-stage fracturing and wellbore commingling to optimize productivity and ultimate reserve recovery. The oil and liquids-rich natural gas production generate a premium netback which further enhances cash flow. Finally, Delphi's ownership in the natural gas gathering systems and gas plants that service the Company's extensive land base ensures our produced volumes will be gathered, processed and marketed in a manner that generates maximum netbacks.

PRODUCTION

In 2009, Delphi's net production increased seven percent to 6,808 barrels of oil equivalent per day (boe/d) from 6,345 boe/d in 2008. During the fourth quarter of 2009, net production increased three percent to 6,888 boe/d from 6,708 boe/d in the fourth quarter of 2008. Fourth quarter and full year production were 84 and 85 percent natural gas, respectively.

The Company's efforts to focus its resources in the Deep Basin area has been successful with approximately 5,050 boe/d or 73 percent of Delphi's fourth quarter volumes coming from the Bigstone, Hythe and Wapiti/Gold Creek areas.

DRILLING

During the year ending December 31, 2009 the Company drilled ten (7.7 net) wells resulting in seven (5.3 net) gas wells and three (2.4 net) oil wells for an overall success rate of 100 percent. In the fourth quarter of 2009, Delphi drilled one (0.5 net) gas well and two (1.4 net) oil wells.

Six (4.3 net) wells drilled in 2009 were vertical wells and four (3.4 net) were horizontal wells. In 2010 Delphi will continue to drill vertical wells and where appropriate, horizontal wellbores with multi-stage fracture stimulations will target specific intervals to enhance overall project economics and capital efficiencies. In many cases the horizontal wells will have completions opportunities in the uphole vertical section, further leveraging the drilling capital and increasing capital efficiency.

PLAY TYPES

Delphi has focused on building a core area in the Deep Basin that positions the Company for economic growth in times of low commodity pricing by targeting predictable and scalable light oil and natural gas opportunities.

Light Oil

The Company is in the process of delineating light oil plays in the Doe Creek formation at Hythe and the Cardium formation at Bigstone with vertical and horizontal wells. At Hythe, two vertical wells are producing Doe Creek oil with first production established in August 2008. During the second half of 2009 Delphi continued development and drilled three horizontal wells targeting the Doe Creek. Stabilized rates from the vertical wells ranged from 30 to 50 boe/d after six months of production and the first horizontal well averaged 430 boe/d during the first two months of production. The remaining horizontal wells are in the process of being completed and production tested with data obtained while drilling indicating similar reservoir characteristics to the first horizontal well. The Company is in the process of delineating this play and initial geologic mapping indicates the reservoir has the potential to extend over multiple sections of high working interest Delphi lands. Regionally there are numerous Doe Creek oil pools that have cumulative production ranging from 1.1 to 1.5 million barrels of oil and Delphi will be applying its knowledge base in search of additional Doe Creek pools. The second light oil play is the Cardium formation in the Bigstone area. At year end, the Company was producing from nine vertical Cardium oil wells in four separate pools, individual well production rates typically stabilized from 30 to 80 boe/d after

three months of production. In December, the Company spud the first of three horizontal Cardium wells planned for the 2009/2010 winter program. Subsequent to December 31, the first horizontal well was drilled, completed and placed on production achieving an average production rate of 530 bbls/d of 50 API light oil and 600 mcf/d for a total of 630 boe/d over a 14 day period. Similar to the Doe Creek at Hythe, initial geologic mapping indicates the reservoir has the potential to extend over multiple sections of high working interest Delphi lands and the Company will continue to delineate the various pools in 2010.

Natural Gas

The Company is also pursuing multi-zone, liquids-rich natural gas in the Cretaceous (Doe Creek, Dunvegan, Paddy, Falher, Blusesky, Gething and Cadomin) and Jurassic (Nikanassin) formations utilizing vertical and horizontal wells. The ability to commingle multiple zones in a single wellbore allows the Company to maximize initial productivity and ultimate reserve recovery in a time frame that greatly enhances the well economics. Typically, three to six individual intervals are completed in a new well and then produced as a commingled stream. Although many of the Company's targeted reservoirs generate attractive economic returns in vertical wells there are additional reservoirs encountered that are marginally economic as a result of lower productivity associated with tighter or laterally discontinuous reservoirs. Historically these reservoirs have been bypassed even though they contain significant quantities of hydrocarbons. Utilizing a combination of horizontal drilling, multi-stage fracturing and multi-zone commingling; these reservoirs are providing a source of repeatable and scalable low risk development opportunities.

At Hythe, the Company initiated a horizontal drilling program to unlock the potential of the under-exploited tight reservoirs with successful drilling and completion of a horizontal well in the Dunvegan formation at a depth of 1,200 metres. The well had an initial 90 day average production rate in excess of 150 boe/d. A second horizontal well targeting the Bluesky at 1,900 metres was completed and brought on-line, subsequent to year end, at an initial production rate of 350 boe/d. A third horizontal well targeting the Falher at 1,700 metres was drilled in the first quarter of 2010. Based on the results from this intial phase of horizontal drilling the Company will be generating a follow up drilling program for the second half of 2010 with the intent of de-risking the various reservoirs on Delphi's 148,000 acre land block at Hythe. At Bigstone the Company is evaluating the use of horizontal wells to increase the potential of intersecting the high deliverability sections of the reservoir that may be laterally discontinuous. A typical Bigstone well has an initial deliverability of 1.0 to 1.5 mmcf/d and some wells have an initial deliverability in excess of 4.0 mmcf/d from laterally discontinuous "sweet spots". The Company is evaluating the use of horizontal wells to increase the chance of intersecting these "sweet spots" and obtain initial production rates and reserve recoveries two to four times that of vertical wells.

Delphi's goal is to apply the appropriate technologies that will result in an optimized development of the identified plays and continue to evaluate the application of these same technologies to new plays.

DELPHI OIL WELLS

DELPHI GAS WELLS

DELPHI FACILITIES & GAS GATHERING SYSTEMS

THIRD PARTY FACILITIES & GAS GATHERING SYSTEMS

BIGSTONE

THE BIGSTONE PROPERTY IS LOCATED 150 KILOMETRES SOUTHEAST OF GRAND PRAIRIE AND REMAINS THE COMPANY'S SINGLE LARGEST PRODUCING ASSET CONTRIBUTING 2,600 BOE/D IN 2009. DELPHI HAS AN AVERAGE WORKING INTEREST OF 56 PERCENT IN 26,100 ACRES OF LAND.

CARDIUM

DUNVEGAN

PEACE RIVER

MANNVILLE

FALHER

BLUESKY

GETHING

CADOMIN

The operated and high working interest nature of these assets allows the Company to efficiently scale a capital program to achieve the objectives of changing internal and external economic conditions. A typical Bigstone well will encounter up to seven productive horizons in the Cretaceous section from 1,900 to 2,800 metres. The multi-zone potential is a major factor in drilling success rates approaching 100 percent since acquiring the property in 2005. The sweet gas produced from these intervals is liquids-rich with condensate yields approaching 30 barrels per million cubic feet of gas resulting in premium product pricing.

PRODUCTION / DRILLING

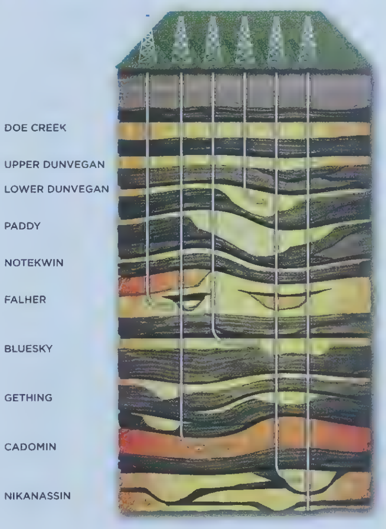
In 2009, net average production decreased ten percent to 2,600 boe/d from 2,900 boe/d in 2008. Production decreases are a result of a limited 2009 capital program while the Company targeted various acquisitions and exploitation of the Hythe assets. The Company is planning an active winter drilling program and expects Bigstone net production rates to return to the historical levels of 2,800 to 3,000 boe/d.

During the year ending December 31, 2009 the Company drilled two (1.3 net) gas wells resulting in a success rate of 100 percent.

HYTHE

THE HYTHE PROPERTY IS LOCATED 60 KILOMETRES NORTHWEST OF GRAND PRAIRIE AND IS THE COMPANY'S SECOND LARGEST PRODUCING ASSET, CONTRIBUTING 1,850 NET BOE/D IN 2009; AN INCREASE OF 360 PERCENT FROM WHEN THE ASSET WAS ACQUIRED IN SEPTEMBER 2007. DELPHI HAS AN AVERAGE WORKING INTEREST OF 63 PERCENT IN 148,000 ACRES OF LAND.

Historically, Hythe has been developed utilizing one vertical gas well per 640 acre spacing unit with one or two zones completed during the initial stage of development. Subsequently, additional zones were accessed as the original completions depleted. A typical Hythe well will encounter up to eight productive horizons in the Cretaceous/Jurassic section from 1,000 to 2,400 metres with individual horizons having multiple productive zones. Once again the multi-zone nature of these assets has resulted in drilling success rates approaching 100 percent since acquiring the property.

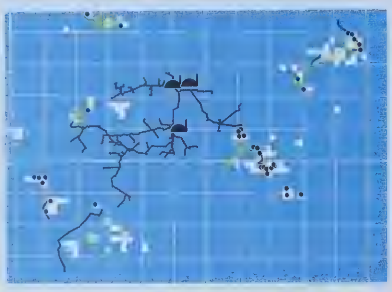


At Hythe, Delphi's initial development drilling plans involved drilling a second vertical well in producing spacing units targeting previously identified productive intervals and completing up to nine zones during the initial completion operations. These efforts were successful in growing production, increasing the reserve base and identifying new development opportunities. During 2009, a second stage of development drilling was initiated incorporating emerging technologies such as horizontal wells with multi-stage fracture stimulations along with traditional drilling and completion methods to enhance production rates, reserve recovery and capital efficiency. Delphi is encouraged by the initial results realized in the second stage of development and is continuing to build a multi-year inventory of drilling and recompletion opportunities.

PRODUCTION / DRILLING

In 2009, net average production increased 85 percent to 1,850 boe/d from 1,000 boe/d in 2008. During the fourth quarter of 2009, net average production increased 53 percent to 2,250 boe/d from 1,475 boe/d in the fourth quarter of 2008.

During the year ending December 31, 2009 the Company drilled six (5.4 net) wells resulting in three (3.0 net) gas wells and three (2.4 net) oil wells for an overall success rate of 100 percent. In the fourth quarter of 2009, Delphi drilled two (1.4 net) oil wells.



WAPITI/GOLD CREEK

THE WAPITI/GOLD CREEK ASSETS ARE LOCATED APPROXIMATELY 60 KILOMETRES SOUTHWEST OF GRAND PRAIRIE AND PRODUCED 520 BOE/D DURING THE FOURTH QUARTER OF 2009. THESE ASSETS WERE ACQUIRED IN TWO SEPARATE TRANSACTIONS IN THE SECOND HALF OF 2009 AND DELPHI CURRENTLY HAS AN AVERAGE WORKING INTEREST OF 56 PERCENT IN 50,800 ACRES OF LAND.

The Wapiti/Gold Creek area is strategically located between the Company's Hythe and Bigstone core areas. Delphi has an ownership in an extensive natural gas infrastructure system including three natural gas processing plants with a combined through-put capacity of 720 million cubic feet per day, ten compressor stations and approximately 400 kilometers of gas gathering and transportation pipelines. The acquisition of these assets is consistent with Delphi's strategy of acquiring multi-zone, sweet gas and natural gas liquids production in the Deep Basin with significant low risk development potential coupled with ownership in key gas infrastructure to support future growth. The properties are characterized by the same Cretaceous and Jurassic producing zones that Delphi is currently exploiting in Bigstone and Hythe. During the winter program, the Company will initiate operations on numerous drilling, completion and optimization projects that were identified as a result of an internal technical review of these assets post acquisition.

A typical Wapiti/Gold Creek well will encounter up to seven productive horizons in the Cretaceous/Jurassic section from 800 to 3,100 metres. The sweet gas produced from these intervals is liquids-rich with condensate yields ranging from 20 to 120 barrels per million cubic feet of gas resulting in premium product pricing and enhanced project economics.

PRODUCTION / DRILLING

Since acquiring the Wapiti/Gold Creek assets in September 2009 the net average production was 460 boe/d and fourth quarter net average production was 520 boe/d.

OTHER PROPERTIES

NORTH WEST AND EAST CENTRAL ALBERTA

In addition to the Bigstone, Hythe and Wapiti/Gold Creek areas; Delphi's primary producing assets in Alberta include; the Tower Creek well southwest of Bigstone, the Fontas area in northern Alberta and several fields in east central Alberta. In 2009, net average production for Alberta, excluding Bigstone, Hythe and Wapiti/Gold Creek, was 1,300 boe/d and during the fourth quarter of 2009 was 1,690 boe/d. The Company did not drill any wells in northern or east central Alberta during 2009.

The Tower Creek well is located 165 kilometres southeast of Grand Prairie. The well was brought on-line in June 2007, has been producing in excess of 19,000 mcf/d since first production and has a cumulative production of 17,600 million cubic feet of gas through December 31, 2009. In 2009, Delphi's net average production from the Tower Creek well was approximately 675 boe/d.

Fontas is located approximately 300 kilometres north of Grande Prairie. In 2009, Delphi's net average production was approximately 200 boe/d from the Mississippian Debolt/Elkton and the Cretaceous Detrital formations, which are typically less than 800 metres in depth. At Fontas, Delphi has a 17 percent working interest in a contiguous land base in excess of 104,000 acres, the gathering system and a 40 mmcf/d processing facility that is tied into the Nova pipeline system.

The east central Alberta properties are classified by the Company as low-risk development assets located in Townships 36 to 41, Range 2 - 12 W4. Production is primarily sweet gas and medium gravity crude from shallow Cretaceous intervals, Delphi's 2009 net average production was approximately 220 net boe/d.

NORTH EAST BRITISH COLUMBIA

In 2009, average production was approximately 450 net boe/d. During the year ending December 31, 2009 the Company drilled one (1.0 net) gas well for an overall success rate of 100 percent.

Delphi's assets in North East B.C. produce from various fields and formations, including the shallow Cretaceous sands at Noel, the deeper Permian Mattson at Windlfower, the Mississippian Debolt at Helmet and the deep Devonian Jean Marie and Slave Point carbonates at Helmet North and Missile. The existing North East B.C. assets generate positive cash flow and provide a solid base from which to build growth type properties such as Bigstone and Hythe. In addition to the indicated development type plays, Delphi has several land blocks that are on trend with emerging Montney and Horn River Basin shale resource plays.

Operational Statistics

RESERVES

GLJ Petroleum Consultants Ltd. (GLJ), an independent petroleum engineering firm, has evaluated the crude oil, natural gas and natural gas liquids reserves of the Company effective December 31, 2009 and prepared a reserves report in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and the Canadian Oil and Gas Evaluation Handbook. Full and complete disclosure information as required by NI 51-101 can be referenced in the Company's Annual Information Form (AIF).

GLJ based its evaluation on land data, well and geological information, reservoir studies, estimates of on-stream dates, contract information, operating cost data, capital budgets and future operating plans provided by the Company, information obtained from public records and GLJ's internal non-confidential files and commodity price forecast. The Audit & Reserves Committee, with the mandate of reviewing the independent engineering report, recommended the acceptance of the GLJ reserve estimates and it has been approved by the Board of Directors for the purposes of the Annual Report and AIF.

RESERVES RECONCILIATION

The reconciliation of the Company's proved, probable and proved plus probable reserves for December 31, 2009 is as follows:

RECONCILIATION OF COMPANY GROSS RESERVES (1)(2)(3)

	Oil (MBBLS)(4)			Natural Gas Liquids (MBBLS)			Associated and Non-associated Gas (MMCF)			MBOE (6:1)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2008	767	493	1,260	896	393	1,288	80,853	35,957	116,809	15,138	6,879	22,016
Extensions and Improved Recovery	374	75	449	88	357	445	7,735	7,406	15,141	1,751	1,666	3,417
Technical Revisions	56	(20)	36	78	(60)	18	2,971	(3,993)	(1,022)	630	(746)	(116)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	99	68	167	551	355	907	19,150	8,185	27,335	3,842	1,788	5,630
Dispositions	(25)	(11)	(35)	(107)	(25)	(132)	(4,115)	(975)	(5,090)	(818)	(197)	(1,015)
Economic Factors	4	(1)	3	(2)	(1)	(3)	(246)	(91)	(337)	(39)	(17)	(56)
Production	(196)		(196)	(182)		(182)	(12,645)	-	(12,645)	(2,485)	-	(2,485)
December 31, 2009	1,080	605	1,684	1,321	1,020	2,341	93,701	46,490	140,191	18,018	9,373	27,391

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.

(2) Gross reserves are estimated using forecast prices and costs.

(3) Tables may not add due to rounding.

(4) Oil is the aggregate of both light and medium crude oil and heavy oil.

SUMMARY OF RESERVES

The following table outlines the oil, natural gas liquids and natural gas reserves of the Company by product type on a gross Company (before royalties and including Company royalty interest) basis. Proved reserves increased 19 percent as compared to year end 2008 and proved plus probable reserves increased by 24 percent. Proved producing reserves account for 45 percent of the Company's total proved plus probable reserves.

Company Gross Reserves(1)(2)(3)	***2009***	*2008*	*% change*
Proved Developed Producing Reserves			
Light and Medium Crude Oil (MBBLS)	***485***	*479*	*1*
Heavy Oil (MBBLS)	***219***	*70*	*213*
Natural Gas Liquids (MBBLS)	***922***	*707*	*30*
Natural Gas Excluding Natural Gas Liquids (MMCF)	***63,910***	*57,952*	*10*
Total MBOE	***12,278***	*10,914*	*12*
Proved Reserves			
Light and Medium Crude Oil (MBBLS)	***834***	*694*	*20*
Heavy Oil (MBBLS)	***246***	*73*	[illegible]
Natural Gas Liquids (MBBLS)	***1,321***	*896*	[illegible]
Natural Gas Excluding Natural Gas Liquids (MMCF)	***93,701***	*80,853*	*16*
Total MBOE	***18,018***	*15,138*	*19*
Proved Plus Probable Reserves			
Light and Medium Crude Oil (MBBLS)	***1,304***	*1,096*	*19*
Heavy Oil (MBBLS)	***381***	*164*	*132*
Natural Gas Liquids (MBBLS)	***2,341***	*1,288*	*82*
Natural Gas Excluding Natural Gas Liquids (MMCF)	***140,191***	*116,509*	*20*
Total MBOE	***27,391***	*22,016*	*24*

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.

(2) Gross reserves are estimated using forecast prices and costs.

(3) Tables may not add due to rounding.

FORECAST PRICES

The following table sets forth a summary of GLJ's January 1, 2010 escalated commodity price, currency exchange rate and inflation rate forecasts used in the preparation of the reserve estimates of the Company.

	West Texas Intermediate (US$/bbl)	Edmonton Light (CDN$/bbl)	AECO Spot (CDN$/mmbtu)	Exchange Rate (US$/CDN$)	Inflation (%)
2010	80.00	83.26	5.96	0.950	2.0
2011	83.00	86.42	6.79	0.950	2.0
2012	86.00	89.58	6.89	0.950	2.0
2013	89.00	92.74	6.95	0.950	2.0
2014	92.00	95.90	7.05	0.950	2.0
2015	93.84	97.84	7.16	0.950	2.0
2016	95.72	99.81	7.42	0.950	2.0
2017	97.64	101.83	7.95	0.950	2.0
2018	99.59	103.88	8.52	0.950	2.0
2019	101.58	105.98	8.69	0.950	2.0
Thereafter [1]	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.950	2.0

(1) Percentage change of 2.0 % represents the change in future prices each year after 2019 to the end of the reserve life.

The Company's weighted average historical prices for 2009 were $6.07/mmbtu for natural gas and $63.87/bbl for it's crude oil blend.

NET PRESENT VALUE OF RESERVES – FORECAST PRICING [1][2]

The net present values of future net revenue of the Company's reserves at various discount rates before deducting future income tax expenses are outlined below.

					Discount Rate
($ thousands)	0%	5%	10%	15%	20%
Proved Developed Producing Reserves	318,778	253,195	211,179	182,164	160,963
Proved Developed Non-Producing Reserves	54,183	37,622	28,865	23,461	19,756
Proved Undeveloped Reserves	77,147	48,703	33,193	23,856	17,772
Proved Reserves	**450,109**	**339,520**	**273,237**	**229,481**	**198,491**
Probable Reserves	267,161	169,511	119,027	89,292	70,087
Proved Plus Probable Reserves	**717,269**	**509,031**	**392,265**	**318,773**	**268,578**

(1) Before deducting future income tax expenses and reclamation costs.

(2) The estimated net present values disclosed do not necessarily represent fair market value.

FINDING AND DEVELOPMENT COSTS

The Company has presented its finding and development costs for its exploration and development program in accordance with NI 51-101. The Company has also calculated other informative finding and development costs, including acquisitions and dispositions, and aggregate of both and has summarized in the table below.

	2009		2008		2007 - 2009	
Capital Invested ($ thousands)	**Total Proved**	**Proved plus Probable**	Total Proved	Proved plus Probable	Total Proved	Proved Plus Probable
Exploration and Development (E&D) Costs	33,946	33,946	76,779	76,779	162,649	162,649
Change in Future Development Costs (FDC) Related to E&D Additions	**(3,132)**	**5,043**	30,561	39,463	31,832	58,195
Change in Future Development Costs Related to Acquisitions and Dispositions	**7,754**	**7,241**	388	552	(2,232)	(12,537)
Total Change in Future Development Costs	**4,622**	**12,284**	30,949	40,015	29,600	45,658
Total Development Costs	**38,568**	**46,230**	107,728	116,794	192,249	208,307
Acquistion Costs	46,887	46,887	[illegible]	[illegible]	[illegible]	[illegible]
Disposition Costs	**(20,718)**	**(20,718)**	(8,450)	(8,450)	(44,670)	(44,670)
Total Costs	**64,737**	**72,399**	137,398	146,464	243,457	259,515
Change in Reserves						
Reserve Additions (mboe)[1]	2,342.0	3,245.0	[illegible]	[illegible]	[illegible]	[illegible]
Aquisitions and Dispositions (mboe)[2]	**3,024.0**	**4,615.0**	1,063.0	1,280.0	3,707.0	4,332.0
Total Reserve Additions (mboe)	**5,366.0**	**7,860.0**	6,112.0	7,077.0	13,378.0	16,828.0
FINDING AND DEVELOPMENT COSTS ($/BOE)						
EXPLORATION AND DEVELOPMENT, INCLUDING CHANGE IN FDC RELATED TO E&D ADDITIONS[3]	**13.16**	**12.02**	21.26	20.05	20.11	17.67
EXPLORATION AND DEVELOPMENT, INCLUDING TOTAL CHANGE IN FDC	16.47	14.25	[illegible]	[illegible]	[illegible]	[illegible]
ACQUISTIONS AND DISPOSITIONS, INCLUDING CHANGE IN FDC RELATED TO A&D[4]	**11.22**	**7.24**	28.28	23.61	13.21	8.93
EXPLORATION, DEVELOPMENT, ACQUISITIONS AND DISPOSITIONS, INCLUDING TOTAL CHANGE IN FDC[5]	**12.06**	**9.21**	22.48	20.70	18.20	15.42

(1) Includes extensions and improved recovery, technical revisions, discoveries, and economic factors.

(2) Includes both acquisition and disposition

(3) Excludes both the future development costs required to develop reserves in the acquisition and disposition categories and the related reserves in the acquisition and disposition categories.

(4) *Includes only the future development costs required to develop reserves in the acquisition and disposition categories and the related reserves in the acquisition and disposition categories.*

(5) *Includes extensions and improved recovery, technical revisions, discoveries, economics factors, acquisitions, and dispositions and the total costs (which include changes in future development costs).*

(6) *The aggregate of the exploration and development costs incurred in the most recent financial year, included in capital invested, and the change in estimated future development costs, generally will not reflect total finding and development costs related to reserve additions for that year.*

RESERVE LIFE INDEX

The reserve life index of Delphi has been calculated by dividing year end 2009 reserves by the average 2009 annual production of 6,808 boe/d. The reserve life index is 11.0 years on a proved plus probable basis.

	Crude Oil and NGL(mbbls)			*Natural Gas (mmcf)*			*Mboe (6:1)*		
	Proved	*Probable*	*Total*	*Proved*	*Probable*	*Total*	*Proved*	*Probable*	*Total*
Reserves - Dec. 31, 2009	2,401	1,625	4,026	93,701	46,490	140,191	18,018	9,373	27,391
Production	378		378	12,645		12,645	2,485		2,485
RESERVES LIFE INDEX (YEARS)	6.4		10.7	7.4		11.1	7.3		11.0

ACREAGE SUMMARY

The Company's total and undeveloped landholdings by province as at December 31, 2009 are outlined below.

	Total		*Undeveloped*		*Fair Market*
December 31, 2009 (acres)	*Gross*	*Net*	*Gross*	*Net*	*Value* [1]
Alberta	499,038	229,368	273,810	141,621	$11,432,500
British Columbia	154,580	46,798	99,086	30,589	$5,262,972
Total	653,618	276,166	372,896	172,210	$16,695,472

(1) *Undeveloped land value of $16,695,472 at December 31, 2009 based on Seaton-Jordan & Associates Ltd. land valuation report.*

RECYCLE RATIO

Recycle ratio is an indicator of the effectiveness of the Company's re-investment program. Recycle ratio is a key measure in the oil and gas industry of capital efficiency and profitability and is calculated here by dividing the finding and development costs for total capital invested by the Company's operating netback [1].

Year ended December 31	**2009**	2008
Operating netback ($/boe) [1]	**24.10**	33.83
Proved plus probable reserves F&D costs ($/boe) [2]	**9.21**	20.70
Proved plus probable recycle ratio	**2.62**	1.63

(1) *Operating Netback is calculated by subtracting royalties, operating costs, and transportation costs from revenues and dividing by Company production in the year.*

(2) *Includes extensions and improved recovery, technical revisions, discoveries, economic factors, acquisitions and dispositions, and the total costs (which include changes in future development costs).*

RESERVE REPLACEMENT

Reserve Replacement Ratio is calculated by dividing Reserve Additions by total 2009 Company production. As the Company had an active year in both its exploration and development program as well as its acquisition and disposition program, calculation for reserve replacement ratio is provided for these as well as total Company below.

	Proved	*Proved + Probable*
Additions (mboe)[1]	2,342	3,245
2009 Production (mboe)	[illegible]	[illegible]
ADDITION REPLACEMENT RATIO	[illegible]	[illegible]
Acquisitions and Dispositions (mboe)[2]	[illegible]	[illegible]
2009 Production (mboe)	2,485	2,485
ACQUISITION AND DISPOSITION RESERVE REPLACEMENT RATIO	**1.22**	**1.86**
Total Reserves Additions (mboe)[3]	5,366	7,860
2009 Production (mboe)	2,485	2,485
TOTAL RESERVE REPLACEMENT RATIO	**2.16**	**3.16**

(1) Includes extensions and improved recovery, technical revisions, discoveries, and economic factors.

(2) Includes Reserve additions from both Acquisitions and Dispositions.

(3) Includes both (1) and (2).

NET ASSET VALUE

The net asset value of the Company at December 31, 2009, using the net present value of future net revenue discounted at a rate of ten percent before deducting future income tax expenses, is summarized below.

($ thousands except per share value)	
Estimated future net revenues of proved plus probable reserves[1]	[illegible]
Undeveloped land[2]	[illegible]
Mark-to-market value of hedging contracts	[illegible]
In-the-money option proceeds[3]	[illegible]
Total assets value	[illegible]
Bank debt plus working capital deficiency	(92,538)
Net asset value	[illegible]
Common shares outstanding and in-the-money options	105,174,132
Net asset value per share	3.09

(1) Discounted at 10 percent and before deducting future income tax expenses and reclamation costs.

(2) Undeveloped land value was determined by an independent land valuation report by Seaton-Jordan & Associates Ltd.

(3) In-the-money option proceeds are based on the closing December 31, 2009 share price of $1.71.

(4) The Company estimates it has approximately $230 million of tax deductions available to offset future taxable income.

Management Discussion And Analysis

(ALL TABULAR AMOUNTS ARE STATED IN THOUSANDS OF DOLLARS, EXCEPT PER UNIT AMOUNTS)

The management discussion and analysis has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp. ("Delphi" or "the Company"). The discussion and analysis is a review of the financial results of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the financial performance for the three and twelve months ended December 31, 2009 and 2008 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2009 and 2008. The discussion and analysis has been prepared as of March 16, 2010.

DELPHI'S BUSINESS

What is the nature of Delphi's business and where are its operations?

Delphi Energy Corp. is a publicly-traded company, listed on the Toronto Stock Exchange, primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations are principally concentrated in North West Alberta, representing 76 percent of its production in 2009. The Company has four primary core areas in the deep basin of North West Alberta located at Bigstone, Hythe, Wapiti/Gold Creek and Tower Creek.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

What were the highlights of Delphi's operational and financial results in 2009?

Early in 2009, it quickly became apparent that the year was going to be very challenging from the perspective of Canadian natural gas prices and the impact of low prices on the Company's and industry cash flow. Capital programs for the industry were reduced early in the year and the environment became very transaction-oriented. Even though Canadian natural gas prices averaged the lowest in 10 years, Delphi Energy Corp. enjoyed one of its most successful years in 2009, accomplishing numerous objectives toward growing long-term value for its shareholders.

The 2009 accomplishments are highlighted as follows:

- achieved record production in 2009 with average daily volumes of 6,808 barrels of oil equivalent per day (boe/d), an increase of seven percent compared to 2008;
- changed the production mix to approximately 16 percent crude oil and natural gas liquids in the fourth quarter of 2009 from 14 percent in the first quarter, which contributed to higher operating and cash flow netbacks;
- generated funds from operations (cash flow) of $49.2 million, a decrease of only 28 percent from the previous year despite a 51 percent drop in AECO natural gas pricing;
- reduced operating costs by 20 percent to approximately $8.56 per boe in the fourth quarter of 2009 from $10.67 per boe in the fourth quarter of 2008;
- realized $23.5 million in hedging gains on natural gas commodity contracts, providing stability to cash flow and providing the ability to pursue the Company's planned capital program;
- increased total proved reserves by 19 percent to 18.0 million boe and increased total proved plus probable reserves by 24 percent to 27.4 million boe;
- drilled ten (7.7 net) wells with an overall success rate of 100 percent, including the drilling of three (2.4 net) horizontal wells utilizing multi-stage fracturing technology into the Doe Creek formation at Hythe Alberta;
- reduced finding, development, acquisitions and dispositions costs to $12.06 per proved boe and $9.21 per proved plus probable boe;

- generated a recycle ratio of 2.6 times on an operating netback of $24.10 per boe;
- completed four strategic acquisitions of natural gas properties and associated infrastructure in the deep basin of North West Alberta to expand the Company's inventory of growth opportunities;
- issued 13.2 million common shares and 3.0 million flow-through common shares in 2009 for gross proceeds of $22.9 million;
- reduced net debt by $16.7 million to $92.5 million at December 31, 2009 from $109.2 million at December 31, 2008, providing $32.5 million of available credit and resulting in a net debt to funds from operations ratio of 1.9:1;
- expanded the Company's lending group through syndication of its credit facilities with the addition of a third chartered bank to facilitate the Company's future growth;
- reduced net debt per boe at December 31, 2009 on a proved developed producing, proved and proved plus probable basis for the third year in a row to $7.54, $5.14 and $3.38 per boe, respectively; and
- increased the Company's total undeveloped land holdings by 37 percent to 172,210 net acres as compared to December 31, 2008.

Cash flow in 2009 was $49.2 million or $0.59 per basic share, compared to $68.7 million or $0.94 per basic share in 2008. For the year ended December 31, 2009, the Company recognized approximately $23.5 million in realized gains on financial and physical hedging contracts providing significant stability to the Company's cash flow. Over the past four years, the Company has realized $44.9 million in gains on physical and financial commodity price contracts. For 2010, the Company has 54 percent of its natural gas production hedged at $6.24 per mcf.

During the year, Delphi altered its capital program to take advantage of light oil opportunities in its portfolio as well as strategic natural gas acquisition opportunities in a transaction-oriented environment. In the latter half of the year Delphi focused its drilling on light oil at Hythe, Alberta and became active in the deep basin of North West Alberta completing several strategic acquisitions at very attractive acquisition metrics. On August 31, 2009, Delphi closed the property and infrastructure acquisition in the Wapiti/Gold Creek areas of North West Alberta. In addition, on August 21, 2009, Delphi announced the acquisition of Fairmount Energy Inc. which closed on November 30, 2009. On September 30, 2009, Delphi announced a property and infrastructure acquisition at Hythe, Alberta which closed on November 3, 2009 and on December 9, 2009 closed an acquisition of properties adjacent to its Hythe area in North West Alberta. These strategic acquisitions provide production, future drilling opportunities on undeveloped land and ownership in key natural gas infrastructure within the Company's core area of focus.

On September 30, 2009, the Company closed an equity offering of 13.2 million common shares at $1.25 per share for gross proceeds of approximately $16.5 million (net proceeds of $15.4 million). Later in the year, on November 16, 2009 the Company closed a flow-through common share offering of 3.0 million shares at $2.12 per share for gross proceeds of $6.4 million (net proceeds of $6.0 million).

Delphi's financial position continues to remain strong at the end of 2009, providing financial flexibility to execute its 2010 capital program and participate in farm-in, joint venture or acquisition opportunities. At December 31, 2009, the Company had net debt of $92.5 million on total credit facilities of $125.0 million, providing excess financial capacity of approximately $32.5 million. On a 12 month trailing funds from operations basis, Delphi's net debt to cash flow ratio was 1.9:1 and 1.6:1 on a net debt to annualized fourth quarter cash flow basis. Net debt includes bank debt plus working capital deficiency excluding the risk management asset/liability and the related current future income taxes.

BUSINESS ENVIRONMENT

What kind of business environment or non-controllable factors did the Company have to contend with in 2009?

The Company is exposed to the volatility in commodity price markets and the change in the foreign exchange rate between the Canadian and United States dollar for pricing of all its production volumes. Project economics are also affected by the cost of industry services. The table below outlines the changes in the various benchmark commodity prices and economic parameters which affect the prices received for the Company's production.

Benchmark Prices and Economic Parameters

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
NATURAL GAS						
NYMEX (US $/mmbtu)	**4.19**	6.83	(39)	**3.90**	8.92	(56)
AECO (CDN $/mcf)	**4.49**	6.70	(33)	**3.96**	8.16	(51)
CRUDE OIL						
West Texas Intermediate (US $/bbl)	**76.17**	58.73	30	**61.93**	99.65	(38)
Edmonton Light (CDN $/bbl)	**76.54**	63.21	21	**66.02**	102.16	(35)
FOREIGN EXCHANGE						
Canadian to US dollar	**1.06**	1.21	(13)	**1.14**	1.06	8
US to Canadian dollar	**0.95**	0.82	15	**0.88**	0.94	(6)

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana (NYMEX) while Canadian natural gas prices are typically referenced to the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system (AECO). Natural gas prices are influenced more by North American supply and demand than global fundamentals, however, with the growth in natural gas liquefaction and regasification facilities around the world this North American supply and demand balance is subject to disruption from time to time. The increase in capacity of natural gas liquefaction and regasification facilities has resulted in natural gas in North America becoming a global commodity, more so through the winter heating season than the summer cooling season, with influences from world weather conditions and global supply in the form of liquefied natural gas (LNG) delivered to the United States.

In the first quarter of 2009, the stability of prices in anticipation of normal withdrawals of natural gas from storage to meet winter heating demand began to slide. The U.S. Midwest and Central Canada were experiencing continuous cold weather resulting in reasonable winter heating demand, however, the U.S. Northeast, representing the largest proportion of winter heating demand, experienced above average temperatures. In addition, industrial demand continued to be significantly reduced due to the current economic slowdown, a trend which persisted throughout the year.

In the second and third quarters of 2009, the U.S. Northeast and Midwest and Central Canada experienced below average seasonal temperatures resulting in reduced average demand for natural gas for electrical generation required to meet the demand for cooling. Downward pressure on natural gas prices, which began early in 2009, continued through the second and third quarters as natural gas storage numbers continued to grow over the five year average levels.

In the fourth quarter of 2009, natural gas prices rebounded in anticipation of winter weather for the coming months and the colder weather received in December of 2009 after a very mild month of November across North America.

The overall drop in natural gas prices for the year had a significant effect on the active drilling rig count in both Canada and the United States but this reduced rig count has not had a significant effect on U.S. natural gas supply and hence storage levels in the United States. Natural gas production failed to decrease in a manner consistent with historical declines associated with reduced drilling activity. Reduced overall drilling for natural gas was more than offset by drilling horizontally into initially higher productivity non-conventional formations, particularly shale gas.

AECO gas prices hit a low of $2.02 per mcf early in September of 2009 but recovered to over $5.00 per mcf at the end of the year. AECO averaged $3.96 per mcf in 2009, 51 percent lower than the previous year.

Crude Oil

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta and represent the WTI price adjusted for quality and transportation differentials as well as the Cdn/US dollar exchange rate. The fundamental supply/demand equation for crude oil is more balanced on a daily basis than natural gas due to consistent demand for crude oil of approximately 85 million barrels per day to meet the global requirement for energy.

Through the first quarter of 2009, the price for crude oil hit its low for the year of U.S. $33.98 per barrel as crude oil supplies continued to grow in the quarter as demand remained reduced due to the slowdown in global economies and use of energy. Since then the price of crude oil has risen steadily to approximately U.S. $80.00 per barrel, with U.S. $76.17 per barrel being the average for the fourth quarter of 2009. The increase reflected stabilization of demand from around the world, while demand from the United States remained below historical levels. In 2009, WTI averaged U.S. $61.93 per barrel, 38 percent lower than the previous year.

In 2009, the general trend for the value of the Canadian dollar against its U.S. counterpart was that of a stronger Canadian dollar. As a producer of crude oil, a stronger Canadian dollar has a negative effect on the price received for production. The exchange rate volatility was affected by the financial markets demand for the United States dollar as a safe haven in these uncertain economic times. The Cdn/US exchange rate varied from a high of $1.31 early in 2009 to a low of $1.03 later in the year. This negative effect to the price of oil for Canadian producers was compounded by a widening basis differential between U.S. and Canadian markets. In 2009, Canadian crude oil prices averaged $66.02 per barrel compared to $102.16 per barrel in 2008, a 35 percent decrease over the previous year.

Prices for heavy oil and other lesser quality crude oils trade at a discount or differential to light crude oil due to the additional costs involved in the refining process. The average differential in 2009 was $8.25 per barrel compared to $18.69 per barrel in 2008. The decrease in the average differential and lower light oil prices, resulted in Bow River crude prices averaging $53.56 per barrel in 2009 compared to $80.95 per barrel in the prior year.

Industry Cost of Services

The decrease in natural gas prices throughout 2009 had a significant negative effect on cash flow available for capital programs and hence drilling and field activity. Drilling contractors and oilfield service companies have had to reduce the rates charged for equipment and labour in order to remain competitive and as active as possible, but at a much slower pace than in previous years. The overall uncertainty in the economy has also led to reduced demand for oilfield services and equipment as many companies have been unable to raise external sources of funding to pursue capital programs.

What does the Company expect in 2010 as it relates to these external factors?

For forecasting purposes, Delphi continues to expect a challenging natural gas market for 2010 as the industrial demand in the United States returns at a slow pace and the U.S. rig count increases, particularly horizontal drilling into the shale gas plays. The Company currently anticipates AECO will average between Cdn $5.00 and $6.00 per mcf in 2010.

While crude oil suffers from a similar concern of oversupply in the short term, the demand for crude oil is still relatively strong as the world's largest source of energy required on a daily basis. Delphi anticipates WTI to average between U.S. $70.00 and $80.00 per barrel for 2010.

The strength or weakness of the Canadian dollar versus the U.S. dollar will largely reflect the global demand for raw materials, particularly metals, minerals and crude oil. The financial markets tolerance for risk and need for financial security in the form of holding U.S dollars will also have a significant effect on the value of the Canadian dollar against the U.S. dollar. Delphi believes the Canadian dollar will remain quite strong in 2010 as global economies recover from the recent slowdown. The Canadian dollar is expected to trade in the $1.00 to $1.05 range against the U.S. dollar.

Delphi continues to monitor the variables affecting the price of natural gas and crude oil in order to ensure its capital program is in line with expected funds from operations.

FINANCIAL STRATEGY

From a financial point of view, are there specific strategies the Company employs to achieve its results and meet forecast expectations?

The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in cash flow resulting from fluctuating commodity prices. Delphi's program involves executing numerous contracts over a period of time to take advantage of the volatility in the natural gas market. The strategy takes advantage of the swings in natural gas prices as a result of a) the changes in demand/supply fundamentals and/or b) the movement of significant financial assets invested in the natural gas market as a pure commodity play. The transactions are generally undertaken for contract terms 12 to 24 months in advance with financially strong counterparties and predominantly executed on a physical basis with the Company's natural gas marketer. Delphi's risk management program consists of fixed price contracts, costless collars, participating swaps and puts and calls which provide downside protection. Costless collars, participating swaps and puts also provide the opportunity to share in the upside if market prices increase above the floor price. If market prices are above fixed price contracts or the ceiling price of costless collars and calls, the Company would continue to achieve its downside protection while realizing losses on these hedging contracts.

Delphi has a strategy of hedging approximately 40 to 50 percent of its natural gas production as long as demand/supply fundamentals indicate volatile markets in the future. Currently, Delphi has hedged approximately 54 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $6.24 per mcf for 2010. This compares to the forward strip commodity price for AECO of $5.40 per mcf for the remainder of 2010 as of February 26, 2010. The following natural gas hedges are in place to support the Company's cash flow.

	Jan - Mar 2010	Apr-Oct 2010	Nov-Mar 2010/11	Apr - Oct 2011
Production hedged (mmcf/d)	18.5	20.9	11.2	2.0
Percentage of natural gas production *	51%	58%	31%	5%
Price floor (Cdn $/mcf)	$6.84	$6.00	$6.23	$5.97

* *based on 36 mmcf/d*

The fair value of outstanding contracts is estimated to be approximately \$6.9 million as of February 26, 2010.

Delphi continues to direct efforts at maintaining or reducing its controllable costs. Increasing production at its various operating fields through Company owned infrastructure reduces fixed costs on a per boe basis and improves netbacks. Field operators are encouraged to undertake preventative maintenance on field infrastructure and wellsite equipment to minimize production downtime and prevent significant operating costs associated with repairs. The Company strives to achieve improvement in its costs of production and at a minimum maintain current production costs.

Maintaining or improving strong operating netbacks per boe through the risk management program and the control of costs associated with production operations, allows the Company to pursue its planned capital program with greater confidence that financial flexibility will be maintained while incurring capital expenditures to grow production volumes. The risk management program has been and will continue to be an integral part of maximizing operating netbacks during periods of price volatility and excess natural gas supply.

As a result of the significant difference in netbacks between crude oil and natural gas, the Company's capital program will be geared more towards oil and liquids-rich natural gas opportunities. By altering the Company's production mix, there is greater certainty of achieving the Company's cash flow expectations due to the higher netback crude oil and liquids production.

The annual net capital expenditure program in the field will continue to approximate forecast cash flow. Additional capital may be approved as a result of opportunistic acquisitions, incremental cash flow from greater than expected production growth, higher than forecast cash netbacks or other sources of financing.

Delphi continues to be focused on reducing its leverage and improving its financial flexibility through net debt reduction or increasing cash flow growth resulting in a lower net debt to funds from operations ratio. The Company continues to be focused on achieving its internal target range for this ratio of 1.3 to 1.5 times. In a low price environment, the Company's objective would be to reduce or at least not increase the net debt balance by undertaking a capital program within cash flow.

SELECTED INFORMATION

Over the past two years, how has Delphi performed and what significant factors contributed to the results?

Over the last eight quarters production has grown from 6,056 boe/d to 6,888 boe/d. Production for the last eight quarters reflects the following events. In 2008, the combination of a successful winter and summer capital program and the production increase from the Peace River Arch acquisition resulted in continued production growth quarter over quarter. In 2009, the Company changed its product focus due to the commodity price environment. In the first six months of 2009, production growth was achieved with drilling success at Bigstone and Hythe, Alberta, primarily focused on natural gas opportunities. With crude oil and natural gas prices going in opposite directions through 2009, the capital program in the second half of 2009 was geared toward drilling for crude oil while acquiring strategic natural gas properties and infrastructure. The Company completed four natural gas property and infrastructure acquisitions in the deep basin of North West Alberta in the latter half of 2009. Fourth quarter production volumes of 6,888 boe per day is record quarterly production for the Company.

Over the past two years, the changes in revenue and cash flow from quarter to quarter primarily reflect the production volumes achieved and the volatility of commodity prices over the past two years with the second quarter of 2008 experiencing peak prices for both crude oil and natural gas.

Natural gas prices over the past two years have generally reflected the cyclical nature of demand. Higher prices in the winter months, reflecting demand for heating, with lower prices through the summer months as production is placed in storage for the upcoming heating season demand. Natural gas prices in the second quarter of 2008 did not follow the cyclical trend expected, as prices continued to increase coming out of the winter heating season due to concerns over natural gas supply in storage and the continued increase in crude oil prices. Subsequent to the second quarter, natural gas prices decreased significantly and then stabilized in the fourth quarter. In 2009, reduced heating and industrial demand due to the economic crisis caused natural gas prices to decrease further as a result of concerns over excess supply relative to demand. The average spot price for AECO in 2009 was $3.96 per mcf, the lowest average price in 10 years. Crude oil prices had recovered to over U.S. $80.00 per barrel by the end of 2009 from a low earlier in the year of U.S. $33.98 per barrel.

The Company achieved record cash flow of approximately $20.0 million in the second quarter of 2008 at the peak of commodity prices. Delphi continues to mitigate the volatility of commodity prices on its cash flow and capital program by undertaking an active risk management program. For the year ended December 31, 2009, the Company recorded cash flow of $49.2 million, during a period of weak commodity pricing. The strong 2009 cash flow is attributed to an increase in production volumes, reduced cost structure and a very successful risk management program.

Net earnings of the Company are primarily driven by the difference between the cash flow netback realized per boe of production versus the Company's depletion, depreciation and amortization (DD&A) rate of $23.63 per boe. The Company continues to reduce its DD&A rate by finding and developing reserves at a cost less than the average DD&A rate. Overall F&D costs of $12.06 per proved boe in 2009 contribute to reduce the overall DD&A rate of the Company.

The following table sets forth certain information of the Company for the past eight consecutive quarters outlining this performance.

	Dec. 31 2009	Sept. 30 2009	Jun. 30 2009	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008	Jun. 30 2008	Mar. 31 2008
PRODUCTION								
Natural gas (mcf/d)	34,626	33,628	35,641	34,813	35,545	33,691	31,898	31,777
Oil (bbl/d)	630	624	371	475	431	372	368	387
Natural gas liquids (bbl/d)	487	544	498	485	353	421	517	372
Barrels of oil equivalent (boe/d)	6,888	6,773	6,809	6,762	6,708	6,409	6,202	6,056
FINANCIAL ($ thousands except per unit amounts)								
Petroleum and natural gas revenue	26,297	24,433	23,229	24,205	30,160	34,461	38,569	32,212
Funds from operations (cash flow)	14,218	12,635	12,371	10,017	13,473	18,160	19,965	17,059
Per share – basic	0.14	0.16	0.16	0.13	0.18	0.24	0.29	0.25
Per share – diluted	0.14	0.16	0.16	0.13	0.18	0.23	0.28	0.25
Net earnings (loss)	1,386	(3,278)	(2,817)	(3,320)	(959)	6,743	49	(739)
Per share – basic	0.02	(0.04)	(0.04)	(0.04)	(0.01)	0.09	-	(0.01)
Per share – diluted	0.02	(0.04)	(0.04)	(0.04)	(0.01)	0.09	-	(0.01)

The decrease in revenue and net earnings from 2008 to 2009 was primarily due to the significant drop in natural gas prices. The increase in revenue and net earnings from 2007 to 2008 was due to a combination of higher production volumes and much higher commodity prices.

	2009	2008	2007
Revenue	98,164	135,402	97,933
Net Earnings/(loss)	(8,029)	5,094	(10,472)
Total assets	361,698	364,538	311,740
Bank debt plus working capital	92,538	109,237	100,658

DRILLING OPERATIONS

How active was Delphi in its drilling program in 2009 and where was the drilling focused?

The Company had another successful year in 2009 drilling 10 gross (7.7 net) wells with a success rate of 100 percent. The drilling was primarily focused on the core properties of Bigstone and Hythe in North West Alberta. In light of decreasing natural gas prices experienced after the first quarter of 2009, the Company deferred much of its drilling for natural gas and focused its efforts on drilling light oil opportunities and pursuing strategic acquisitions in its core areas. By the end of the year, Delphi had drilled three horizontal wells using multi-stage fracturing technology in the Hythe area pursuing light oil in the Doe Creek formation.

	Three Months Ended December 31, 2009		Twelve Months Ended December 31, 2009	
	Gross	Net	Gross	Net
Natural gas wells	1.0	0.5	7.0	5.3
Oil wells	2.0	1.4	3.0	2.4
Total wells	3.0	1.9	10.0	7.7
Success rate (%)	100	100	100	100

What are the Company's drilling plans for 2010?

The capital program for 2010 consists of a broad range of projects including the drilling of up to 24 (17.6 net) wells. The focus of the program will continue to be on light oil and natural gas opportunities in Bigstone and Hythe with several wells being drilled in the Company's newly acquired Wapiti/Gold Creek area pursuing liquids-rich natural gas opportunities. The program will consist of both vertical and horizontal drilling using multi-stage fracturing technology in horizontal wells and multiple completions for commingled production in vertical wells.

CAPITAL INVESTED

How much did the Company spend in 2009 and where were the capital expenditures incurred?

The Company continued to direct its capital program at its core areas of Bigstone and Hythe to take advantage of the multi-zone nature of these assets, low production operating costs and quick on-stream capability associated with owned gathering and processing infrastructure. Total capital invested in the field was $33.9 million with approximately 63 percent directed at drilling and completion operations and 20 percent incurred on equipping and facility projects. Delphi spent $0.8 million in acquiring 12,769 net acres of land at Crown sales in 2009. Delphi was also active in closing several strategic acquisitions in 2009 for $30.9 million and the disposition of certain royalty interests on properties, the granting of an overriding royalty at Bigstone and the sale of non-core assets for total proceeds of $20.7 million. Total capital invested in 2009 was $60.1 million, including the costs of the corporate acquisition of Fairmount Energy Inc.

How did the Company tailor its capital program to the commodity price environment experienced in 2009, particularly the low natural gas prices?

As a result of the reduction in natural gas prices while crude oil prices steadily increased throughout the year, the Company chose to reduce its drilling program for natural gas after the first quarter of 2009 and focus its capital program on light oil opportunities and strategic natural gas acquisitions that were available in the marketplace. In the third quarter of 2009, the Company drilled only one light oil well at Hythe, Alberta and used the majority of its cash resources to close an acquisition on August 31, 2009 of predominantly natural gas producing properties in North West Alberta for cash consideration of $19.3 million. Upon closing the acquisition, the Company immediately disposed of 40 percent of the acquired working interest in the properties for cash proceeds of $7.9 million. The properties are located directly south of the Company's core area of Hythe, Alberta in the Wapiti/Gold Creek area. The acquisition included a working interest in three natural gas processing plants and a significant web of pipelines connected to these processing facilities.

Upon announcing the acquisition in the Wapiti/Gold Creek area, Delphi subsequently announced the acquisition of Fairmount Energy Inc. on the basis of 0.3571 of a common share of Delphi for each common share of Fairmount pursuant to a take-over bid circular. On October 8, 2009, the Company took up and paid for 76 percent of the common shares of Fairmount Energy Inc. and by November 30, 2009 Delphi owned 100 percent of the common shares of Fairmount. Fairmount and its subsidiaries were amalgamated into Delphi by December 31, 2009.

In the fourth quarter of 2009, the Company continued acquiring assets which were strategic to long-term growth in the deep basin. On November 3, 2009 Delphi closed an asset exchange agreement with a joint venture partner in the Hythe area, resulting in an increased working interest and new working interest on lands in the area in addition to an increased working interest at the Goodfare plant in the Hythe area and a working interest in two additional natural gas processing facilities. In exchange, the Company paid cash consideration of $10.0 million and non-core assets in the Peace River Arch area of North West Alberta with related infrastructure. On December 9, 2009, the Company closed an acquisition of natural gas properties adjacent to its Hythe area for cash consideration of $1.6 million.

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2009	2008	% Change	**2009**	2008	% Change
Land	**(155)**	612	-	**828**	742	12
Seismic	**(11)**	44	-	**369**	766	(52)
Drilling and completions	**5,803**	9,282	(37)	**21,327**	53,672	(60)
Equipping and facilities	**1,198**	4,725	(75)	**6,789**	17,572	(61)
Capitalized expenses	**1,579**	839	88	**4,202**	3,273	28
Other	**28**	158	(82)	**431**	754	(43)
Capital invested	**8,442**	15,660	(46)	**33,946**	76,779	(56)
Disposition of properties	**(10,765)**	-	(100)	**(20,718)**	(8,450)	145
Net capital invested	**(2,323)**	15,660	-	**13,228**	68,329	(81)
Acquisition of properties	**11,422**	174	6,464	**30,873**	38,120	(19)
Acquisition of Fairmount	**16,014**	-	100	**16,014**	-	100
Total capital invested	**25,113**	15,834	59	**60,115**	106,449	(44)

* *The costs of the acquisition of Fairmount Energy Inc. include debt plus working capital on the date of acquisition plus shares issued on the exchange and transaction costs.*

The winter program commenced in the fourth quarter with a continued focus on light oil opportunities and an increased utilization of horizontal drilling and multi-stage fracture stimulation.

Proceeds from dispositions in 2009 consisted of the right-sizing of an asset acquisition by disposing of 40 percent of the acquired working interest for cash proceeds of $7.9 million immediately after closing, the disposition of several non-core assets for proceeds of $2.5 million, the disposition of certain royalty interests for $2.3 million and the granting of a five percent gross overriding royalty on its Bigstone property for proceeds of $8.0 million. Total proceeds on dispositions were $20.7 million in 2009.

What are the Company's expectations for capital spending in 2010?
The Company's planned 2010 capital program is approximately $60.0 to $65.0 million, consistent with the Company's cash flow expectations for the year. The program consists of a broad range of projects including drilling wells, well and infrastructure optimization projects, pipeline and facility projects and recompletions. The program is designed to provide high netback production from light oil and liquids-rich natural gas opportunities, continue to demonstrate the economic viability of conventional natural gas opportunities in the deep basin and utilize multi-stage fracturing technology to enhance productivity, increase reserve recovery and further expand the Company's scalable resource-style play types.

PRODUCTION

In a challenging environment for the energy industry, was Delphi successful in achieving year over year production growth and has the production mix changed to maximize revenue?
Production for the twelve months ended December 31, 2009 averaged 6,808 boe/d representing an increase of seven percent over the comparative period primarily due to the successful drilling and optimization programs at Bigstone and Hythe and the closing of strategic acquisitions in the Company's core areas. The ability to achieve production growth in a weak natural gas pricing environment is a testament to the quality of the asset base, technical expertise of the staff and management and the financial flexibility of the Company. A significant undeveloped land base, multi-zone potential and the successful application of emerging technologies continue to provide material growth opportunities in existing and new play concepts. The Company's production portfolio for the year was weighted 85 percent to natural gas, eight percent to crude oil and seven percent to natural gas liquids. With favorable netbacks on crude oil production, Delphi has been focused on increasing crude oil production to maximize netbacks and has achieved a 35 percent increase in crude oil production over 2008. The Doe Creek and Cardium plays will provide Delphi with the opportunity to significantly increase the production mix of light oil.

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2009	2008	% Change	**2009**	2008	% Change
Natural gas (mcf/d)	**34,626**	35,545	(3)	**34,673**	33,236	4
Crude oil (bbls/d)	**630**	431	46	**525**	390	35
Natural gas liquids (bbls/d)	**487**	353	38	**504**	416	21
Total (boe/d)	**6,888**	6,708	3	**6,808**	6,345	7

Crude oil production was 35 percent higher than the previous year. The increase in oil production is due to the successful drilling and optimization program targeting the Doe Creek light oil discovery at Hythe, Alberta.

Natural gas liquids were 21 percent higher for the year primarily due to the increased natural gas liquids production at Progress, Alberta.

REALIZED SALES PRICES

What were the sales prices realized by the Company for each of its products?

For the three and twelve months ended December 31, 2009, Delphi's risk management program realized a gain of \$4.5 million and \$23.5 million, respectively. For the quarter, the realized gain was \$1.41 per mcf with physical contracts contributing a gain of \$1.32 per mcf and financial contracts contributing a gain of \$0.09 per mcf. For the year ended December 31, 2009, the average realized natural gas price was 31 percent less than the comparative period due to a 51 percent decrease in the AECO spot price offset by significant realized hedging gains.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
AECO (\$/mcf)	**4.49**	6.70	(33)	**3.96**	8.16	(51)
Heating content and marketing (\$/mcf)	**0.25**	0.83	(69)	**0.26**	0.59	(57)
Gain (loss) on physical contracts (\$/mcf)	**1.32**	0.50	165	**1.57**	(0.01)	-
Gain (loss) on financial contracts (\$/mcf)	**0.09**	0.11	(20)	**0.28**	0.02	1,301
Realized natural gas price (\$/mcf)	**6.15**	8.14	(24)	**6.07**	8.76	(31)
Realized oil price (\$/bbl)	**74.13**	54.55	34	**63.87**	89.88	(29)
Realized natural gas liquids price (\$/bbl)	**53.02**	28.11	89	**48.50**	80.49	(40)
Total realized sales price (\$/boe)	**41.50**	48.87	(15)	**39.50**	58.31	(32)

Delphi's oil production is a mix of light and medium oil; therefore the Company's average price fluctuates with the change in the benchmark crude oil prices and the quality differential. Increased production of light oil at Bigstone and Hythe continues to high grade the Company's quality of crude oil resulting in pricing more reflective of light oil. The Company's realized crude oil and natural gas liquids prices were significantly lower than the comparative quarter in the previous year as a result of the significant drop in benchmark prices.

How do the realized natural gas prices compare to the benchmark AECO pricing?

Excluding hedges, the Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of its natural gas production and the sale of approximately 3,500 million British thermal units (mmbtu) per day on the Alliance pipeline which is priced at the Chicago Monthly Index.

The following table outlines the premium (discount) Delphi realized on natural gas prices compared to the average quarterly AECO price due to the risk management program, quality of production and gas marketing arrangements. In years of both high and low commodity price environments, Delphi's realized sales price has benefited from a premium to AECO.

	Dec. 31 2009	Sept. 30 2009	Jun. 30 2009	Mar. 31 2009	Dec. 31 2008	Sept.30 2008	Jun. 30 2008	Mar. 31 2008
Natural Gas Price								
Delphi realized ($/mcf)	6.15	5.77	5.81	6.55	8.14	8.28	9.66	8.91
AECO average ($/mcf)	4.49	2.94	3.47	4.95	6.70	7.73	10.22	7.97
Premium (discount) to AECO	37%	96%	67%	32%	21%	7%	(5%)	12%
Hedging gain (loss) ($000's)	4,498	7,973	6,997	3,991	1,985	(67)	(3,153)	1,371

RISK MANAGEMENT ACTIVITIES

What is Delphi's risk management strategy and what contracts are in place to mitigate the risk of volatility?

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to ensure sufficient cash is generated to fund its capital program particularly when commodity prices are extremely volatile. Delphi makes a concerted effort to hedge production volumes at prices greater than the upper limit of the historical three to five year AECO price range of $5.25 to $8.40 per mcf and is quick to react to price aberrations such as those experienced at the end of 2005 and the summer of 2008. Another component of the risk management program is to layer in contracts over a period of time, as opposed to locking in a significant portion of volumes at any one point in time, to take advantage of unexpected price spikes. For natural gas production, Delphi has hedged approximately 54 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $6.24 per mcf for 2010.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the statement of operations. Physical commodity sale contracts based in U.S. dollars include an embedded derivative associated with the foreign exchange rate. Due to this derivative, the changes in the fair value of these contracts are included in the statement of earnings.

The Company recognized an unrealized non-cash loss on its financial contracts and United States dollar denominated physical contracts of $2.1 million for 2009. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

The Company has fixed the price applicable to future production through the following contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
April 2009 – March 2010	Natural Gas	Physical	3,000 GJ/d	$7.52 fixed
April 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$6.80 floor plus 50% > $6.80
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$8.70 ceiling
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.26 floor plus 50% > $7.26
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.65 floor plus 50% > $7.65
January 2010 – December 2010*	Natural Gas	Financial	3,500 GJ/d	$7.40 Call
January 2010 – December 2010*	Natural Gas	Physical	3,500 GJ/d	$7.15 Call
January 2010 – December 2010	Crude Oil	Financial	100 bbls/d	$86.40 fixed
January 2010 – December 2010	Crude Oil	Financial	100 bbls/d	$72.20 floor/$100.00 ceiling
January 2010 – March 2011	Natural Gas	Physical	1,500 GJ/d	$5.74 fixed
January 2010 – March 2011	Natural Gas	Financial	2,000 GJ/d	$5.72 fixed
February 2010 – March 2010	Natural Gas	Financial	5,000 GJ/d	$5.00 Put
February 2010 – March 2010	Natural Gas	Financial	2,500 GJ/d	$5.03 Put
April 2010 – October 2010**	Natural Gas	Financial	2,500 GJ/d	$4.75 Put
April 2010 – October 2010	Natural Gas	Financial	2,000 GJ/d	$5.53 fixed
April 2010 – October 2010	Natural Gas	Financial	1,500 GJ/d	$4.80 floor plus 50% > $4.80
April 2010 – December 2010	Natural Gas	Physical	3,000 GJ/d	$6.25 floor/$7.47 ceiling
April 2010 – December 2010	Natural Gas	Physical	4,000 GJ/d	$5.93 floor plus 50% > $5.93
April 2010 – March 2011	Natural Gas	Physical	3,000 GJ/d	$6.12 fixed
April 2010 – March 2011	Natural Gas	Physical	2,500 GJ/d	$5.73 fixed
January 2011 – December 2011**	Natural Gas	Financial	2,500 GJ/d	$7.14 Call
April 2011 – October 2011	Natural Gas	Physical	2,000 GJ/d	$5.66 fixed

* *The 2010 call contracts were executed in 2009 to obtain a $6.00 put in 2009 on a costless basis.*

** *The Company has acquired a natural gas put contract at $4.75 per gigajoule on 2,500 gigajoules per day for the period April 1, 2010 through October 31, 2010. This put was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $7.14 per gigajoule for the period January 1, 2011 through December 31, 2011.*

The Company accounts for its Canadian dollar physical sales contracts, which were entered into and continue to be held for the purpose of delivery of production, in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives.

REVENUE

How do revenues in 2009 compare to 2008 and what factors contributed to the change?

In 2009, Delphi generated revenue of $98.2 million, representing a decrease of 28 percent, compared to the prior year's revenue of $135.4 million. The decrease in revenue is a result of offsetting variables. In 2009, Delphi increased its production by seven percent to 6,808 boe/d compared to 6,345 boe/d in 2008, however, the price received for this higher production was lower than 2008 as a result of lower overall commodity prices. The average price realized per boe in 2009 was 32 percent lower at $39.50 per boe compared to $58.31 per boe in 2008, a greater decrease than the growth in production volumes resulting in the lower revenues.

In the fourth quarter of 2009, revenue of $26.3 million was down 13 percent over the same period in 2008. The decrease was attributed to lower commodity pricing offset by record production volumes in the fourth quarter of 2009.

What is the breakdown of revenues by product and the overall contribution to revenue of the risk management program?

Delphi is predominantly a natural gas producer due to the nature and location of its assets. Hence 54 percent of the Company's revenue for the year was from natural gas sales at market prices, crude oil represented 13 percent and natural gas liquids contributed nine percent. The risk management program associated with natural gas pricing generated revenue of $23.5 million in 2009 or 24 percent of total revenues.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
Natural gas	**15,093**	25,006	(40)	**53,363**	106,425	(50)
Natural gas physical contract gains (losses)	**4,218**	1,617	161	**19,913**	(141)	-
Crude oil	**4,239**	2,163	96	**12,238**	12,830	(5)
Natural gas liquids	**2,376**	913	160	**8,922**	12,255	(27)
Sulphur	**91**	93	(2)	**182**	3,755	(95)
Natural gas financial contract gains (losses)	**280**	368	(24)	**3,546**	278	1,176
Total	**26,297**	30,160	(13)	**98,164**	135,402	(28)

ROYALTIES

What are the types of royalties the Company pays to produce oil and gas?

The Company pays royalties to provincial governments, individuals and companies that own surface and/or mineral rights. These payments take the form of Crown, freehold and overriding royalties. Crown royalty rates for crude oil and natural gas are generally calculated on a sliding scale based on commodity prices and production rates whereas freehold and overriding royalty rates are generally a fixed percentage of revenue. Crown royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to minimum and maximum rates. For natural gas liquids, Crown royalty rates are a fixed percentage of revenue with the rate varying according to the nature of the product. Crown royalty credits are credits received from the Crown and represent the fee earned by the owners of natural gas processing infrastructure to process the Crown's royalty share of natural gas. Royalties are not affected by gains or losses realized through the Company's risk management program.

Were royalties affected by any new regulations or incentive programs in 2009?

In October 2007, Alberta's New Royalty Framework (NRF) was announced increasing the overall royalty rates for higher prices and high productivity wells while reducing royalty rates for lower prices and lower productivity wells. The NRF rates apply to both new and existing production and became effective January 1, 2009. As a result of the decrease in commodity prices experienced in the latter half of 2008 and commensurate reduction in field activity by oil and gas producers, in November 2008 the Government of Alberta announced royalty relief which provided that for new wells drilled after November 19, 2008, the Company could elect to have the pre-NRF royalty regime apply on those wells. Drilling activity continued to be depressed early in 2009 so on March 3, 2009, the Alberta Government announced further royalty incentives to promote oilfield activity in light of the current economic environment. The incentives provided drilling credits of $200 per metre subject to royalties paid to the Crown and the size of the company and a reduced royalty rate of five percent for new production brought on-stream after March 31, 2009 subject to a maximum volume produced after which NRF royalty rates would apply. On June 25, 2009 the Alberta Government announced an extension of this drilling credit and royalty incentive program to March 31, 2011 from March 31, 2010. The drilling credits are accounted for as a reduction of capital invested rather than a reduction of royalties.

What were royalty costs in 2009?

In 2009, the Company paid Crown, freehold and gross overriding royalties. Crown royalties of $14.1 million were partially offset by $7.3 million of royalty credits with the net amount of $6.8 million representing 76 percent of the total royalties paid in 2009 compared to 92 percent in 2008. The net Crown royalties were significantly lower than the $23.7 million paid in 2008 primarily as a result of much lower average commodity prices, particularly natural gas prices, as well as the impact of the NRF royalty rates and royalty incentive programs on new production post November 18, 2008 and March 31, 2009. The significant increase in royalty credits received in 2009 is a result of the Company's growing ownership in natural gas processing infrastructure in North West Alberta. In the second quarter of 2009, the Company received a royalty credit adjustment of $0.9 million related to the prior year.

Freehold royalties were $0.4 million in 2009, compared to $0.7 million in 2008 due to lower commodity prices. Freehold royalties represent four percent of the total royalties paid versus three percent in 2008.

Gross overriding royalties represented 20 percent of total royalties in 2009 compared to six percent in 2008. The increase in gross overriding royalties to $1.8 million in 2009 compared to $1.5 million in 2008 is primarily a result of various farm-in transactions undertaken by the Company.

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2009	2008	% Change	**2009**	2008	% Change
Crown royalties	3,316	5,976	(45)	14,134	26,884	(47)
Royalty credits	**(1,863)**	(1,173)	59	**(7,337)**	(3,174)	131
Crown royalties – net	**1,453**	4,803	(70)	**6,797**	23,710	(71)
Freehold royalties	91	172	(47)	361	663	(46)
Gross overriding royalties	**1,016**	292	248	**1,824**	1,454	25
Total	**2,560**	5,267	(51)	**8,982**	25,827	(65)
Per boe	**4.04**	8.53	(53)	**3.61**	11.12	(68)

What were the average royalty rates paid on production in 2009?

The significant change in royalty rates for 2009 as compared to 2008 was due to lower Crown royalties. The Crown royalty rate, after royalty credits, decreased to nine percent of revenue versus 18 percent of revenue, a decrease of 50 percent. The lower Crown royalty rate was primarily due to the low natural gas prices and the associated royalty rates under the NRF. The gross overriding royalty rate increased to two percent in 2009 from one percent in the prior year.

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2009	2008	% Change	**2009**	2008	% Change
Crown rate – net of royalty credits	**7%**	17%	(59)	**9%**	18%	(50)
Gross overriding rate	**4%**	1%	300	**2%**	1%	100
Average rate	**11%**	18%	(39)	**11%**	19%	(42)

The royalty rate calculations above exclude gains or losses on risk management activities from revenue as the denominator.

What are the Company's expectations for royalty rates in 2010?

Delphi's average royalty rate for 2010 will ultimately be determined by the production rate of individual wells and commodity prices. Based on the Company's forecast of U.S. $75.00 per barrel of crude oil and an AECO spot price of Cdn $5.70 per mcf, Delphi anticipates its average royalty rate in 2010 to average between 15 and 17 percent. Similar to 2009, for 2010 the Company will continue to receive the royalty credits for processing the Crown share of natural gas and natural gas liquids production and the credits received may be greater in 2010 as a result of the acquisition of additional working interests in natural gas processing facilities as part of the Company's property acquisitions throughout 2009. The five percent royalty rate on new production in 2010 will also continue to have a positive effect on royalty rates.

OPERATING EXPENSES

How has the Company been able to reduce its operating expenses in 2009 as compared to 2008?

Operating costs on a per boe basis for the twelve months ended December 31, 2009, decreased 12 percent over the comparative year. The decrease is attributed to lower field operating costs as well as increased volumes from the cost efficient core areas of Hythe, Wapiti/Gold Creek, and Bigstone. The Company has accumulated additional infrastructure in its core areas during 2009 which will allow for lower per boe operating costs as production volumes grow. Operating costs in the fourth quarter of 2009 were $6.76 per boe which represents a 37 percent decrease over the $10.67 per boe experienced in 2008. The fourth quarter reduction can be attributed to increased operating efficiencies as well as favorable prior period adjustments for natural gas plant equalizations which decreased operating costs by $1.80 per boe in the fourth quarter. Excluding the favorable prior period adjustments, Delphi's corporate operating costs in the fourth quarter were $8.56 per boe.

The Company earns processing income on third party production volumes going through facilities owned by Delphi. The processing income represents a reduction of the Company's costs to operate those facilities and hence is deducted in determining operating expenses. Processing income indicates the Company has excess capacity at its facilities which it can access to handle growth in its production volumes.

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2009	2008	% Change	**2009**	2008	% Change
Production costs	4,856	7,092	[illegible]	[illegible]	[illegible]	[illegible]
Processing income	**(571)**	(507)	13	**(2,892)**	(1,627)	78
Total	**4,285**	6,585	(35)	**22,551**	24,092	(6)
Per boe	**6.76**	10.67	(37)	**9.08**	10.37	(12)

What are the Company's expectations for operating costs in 2010?

Delphi continues to focus on cost reduction and has directed staff in all facets of the business to look for potential cost efficiencies. The corporate strategy to improve cost structure is working as the Company anticipates 2010 operating costs in the $8.50 to $9.00 per boe range.

TRANSPORTATION EXPENSES

How are transportation costs different from operating costs?

Transportation expenses are costs incurred by the Company to transport its production volumes from the wellhead to the point of sales. In British Columbia, infrastructure is owned by Spectra Energy that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
Total	**1,499**	2,320	(35)	**6,739**	6,944	(3)
Per boe	**2.37**	3.76	(37)	**2.71**	2.99	(9)

What factors contributed to the decrease in transportation costs in 2009 and what are the Company's expectations for transportation costs in 2010?

On a per boe basis, transportation costs for the three and twelve months ended December 31, 2009, decreased by 37 percent and nine percent, respectively, over the comparative periods. Effective November 1, 2007 and again on November 1, 2008, Delphi transferred a portion of its excess processing and transmission capacity in North East British Columbia to third parties resulting in reductions in transportation costs. Delphi expects transportation costs to be between $2.40 and $2.80 per boe for 2010.

GENERAL AND ADMINISTRATIVE

In a year of challenging commodity prices, did the Company make changes to its staff count?

The environment in 2009 provided the opportunity to recruit talented professionals from competitors which were faced with reduced capital programs due to the pricing environment. The Company took this opportunity in 2009 to increase its technical team with the addition of seven engineering, geological and operations professionals experienced in the deep basin where the Company is focused.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
General and administrative costs	**4,475**	2,377	88	**12,123**	9,352	30
Overhead recoveries	**(261)**	(291)	(10)	**(888)**	(1,173)	(24)
Salary allocations	**(2,033)**	(636)	220	**(5,447)**	(3,400)	60
Net	**2,181**	1,450	50	**5,788**	4,779	21
Per boe	**3.44**	2.35	46	**2.33**	2.06	13

[illegible]trative costs in 2009 compare to 2008 and what do you expect in 2010?

On a per boe basis, general and administrative (G&A) costs for the twelve months ended December 31, 2009 increased 13 percent over the comparative period in 2008 due to an increase in the number of employees, costs of retaining personnel and a reduction in overhead recoveries associated with a lower field capital program. Delphi is committed to delivering strong growth and believes a strong team is paramount to achieve this goal. For 2010, Delphi is expecting G&A per boe to be approximately $2.00 to $2.25 per boe.

STOCK-BASED COMPENSATION

What is stock-based compensation expense?

Stock-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors and key consultants of the Company. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
Stock-based compensation	**301**	314	(4)	**1,467**	2,114	(3
Capitalized costs	**(161)**	(55)	193	**(852)**	(1,120)	(2
Net	**140**	259	(46)	**615**	994	(38,
Per boe	**0.22**	0.42	(47)	**0.25**	0.43	(42)

With the increase in staff in 2009, what was the affect on stock-based compensation?

Despite the growth in the team at Delphi, the reduction in stock-based compensation expense was primarily due to the lower fair value of options calculated in 2009 versus 2008 using the Black-Scholes option pricing model. The average cost of grants in 2009 was $0.43 per option versus $1.13 per option for grants in 2008. The non-cash stock-based compensation expense per boe for the twelve months ended December 31, 2009, decreased 42 percent over the comparative period. During the three and twelve months ended December 31, 2009, Delphi capitalized $0.2 million and $0.9 million, respectively, of stock-based compensation associated with exploration and development activities.

INTEREST

How do the costs of borrowing compare against the prior year?

For the three and twelve months ended December 31, 2009, interest expense on a per boe basis increased 42 percent and decreased 11 percent over the comparative periods. The increase over the comparative quarter was due to the increased pricing on the Company's credit agreement established late in the second quarter, reflective of higher market credit spreads. For the twelve months ended December 31, 2009, the lower costs reflect higher production volumes and lower benchmark interest rates over the period.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
Total	**1,555**	1,065	46	**4,863**	5,103	(5)
Per boe	**2.45**	[illegible]	[illegible]	[illegible]	[illegible]	

During 2009, the Company converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. At December 31, 2009, the bankers' acceptances have terms ranging from 90 to 182 days and a weighted average effective interest rate of 4.9 percent over the term.

What has the Company done to protect itself against an increase in interest rates?

The Company has entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $40.0 million maturing on May 4, 2011. The bankers' acceptance rate on the transaction will increase in fixed monthly increments of 4.55 basis points for an average fixed rate over two years of 0.94 percent. The effective interest rate over the two year term on $40.0 million of bankers' acceptances will be 0.94 percent plus the applicable stamping fee.

DEPLETION, DEPRECIATION AND ACCRETION

How has the Company's depletion and depreciation rate and expense changed in 2009 as compared to 2008?

Depletion and depreciation per boe for the three and twelve months ended December 31, 2009 decreased 13 and five percent over the comparative periods. With continued drilling success at Bigstone and Hythe, Delphi has been able to add proved reserves at a cost below the Company's current depletion rate. The decrease in total depletion and depreciation was a result of the depletion costs associated with increased production being more than offset by the improvement in the depletion rate.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
Depletion and depreciation	**13,271**	15,333	(13)	**57,906**	61,095	(5)
Accretion expense	**219**	200	10	**818**	650	26
Total	**13,490**	15,533	(13)	**58,724**	61,745	(5)
Depletion and depreciation per boe	**20.94**	24.85	(16)	**23.30**	26.31	(11)
Accretion per boe	**0.35**	0.32	9	**0.33**	0.28	17
Total per boe	**21.29**	25.17	(15)	**23.63**	26.59	(11)

What is accretion expense and how did this expense for 2009 compare to 2008?

The accretion of asset retirement obligations is an expense that relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards. Due to the long term nature of certain assets of the Company, this accretion expense is estimated to extend over a term of three to 20 years. The Company uses a credit adjusted risk-free interest rate of eight to ten percent for the purpose of calculating the fair value of its asset retirement obligations and hence the accretion expense. The accretion expense for the three and twelve months ended December 31, 2009 increased ten percent and 26 percent respectively over the comparative periods due to the wells acquired through acquisitions during the year.

INCOME TAXES

What was the affect on future income taxes as a result of the loss in the year?

The provision for future income taxes in the financial statements for the three and twelve months ended December 31, 2009, was a reduction of $1.0 million and $4.2 million, respectively. Delphi does not anticipate it will be cash taxable before 2012.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	% Change	**2009**	2008	% Change
Current	**-**	-	-	**-**	-	-
Future (reduction)	**(1,031)**	(798)	29	**(4,171)**	1,432	-
Total	**(1,031)**	(798)	29	**(4,171)**	1,432	-
Per boe	**(1.63)**	(1.29)	26	**(1.68)**	0.62	-

FUNDS FROM OPERATIONS

What are funds from operations and why is it a key performance measure?

Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings (loss) plus the add back of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gain (loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. Delphi uses funds from operations (cash flow) to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments to grow the Company's value for the shareholders and to repay debt.

How do funds from operations in 2009 compare to 2008?

For the three and twelve months ended December 31, 2009, funds from operations were \$14.2 million (\$0.14 per basic share) and \$49.2 million (\$0.59 per basic share) compared to \$13.5 million (\$0.18 per basic share) and \$68.7 million (\$0.96 per basic share) in the comparative periods. The decrease in funds from operations is a result of a reduction in revenue received per boe being partially offset by an increase in production volumes, reduced royalty rates and a reduction in operating costs per boe.

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2009	*2008*	*% Change*	***2009***	*2008*	*% Change*
Net earnings (loss)	**1,386**	(959)	-	**(8,029)**	5,094	
Non-cash items:						
Depletion, depreciation and accretion	**13,490**	15,533	(13)	**58,724**	61,745	(5)
Unrealized loss (gain) on risk management activities	**233**	(562)	-	**2,102**	(608)	-
Stock-based compensation expense	**140**	259	(46)	**615**	994	(38)
Future income taxes (reduction)	**(1,030)**	(798)	[illegible]	[illegible]	[illegible]	
Funds from operations	**14,218**	13,473	6	**49,241**	68,657	(28)

How do funds from operations compare to cash flow from operating activities in the financial statements?

Funds from operations reflect two primary differences from the GAAP term cash flow from operating activities shown on the financial statements. These differences are expenditures incurred for asset retirement obligations and reclamation and changes in non-cash operating working capital. The following table is a reconciliation of funds from operations to cash flow from operating activities for the three and twelve months ended December 31, 2009 and 2008.

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2009	*2008*	*% Change*	***2009***	*2008*	*% Change*
Funds from operations: Non-GAAP	**14,218**	13,473	6	**49,241**	68,657	(28)
Settlement of asset retirement obligations	**(167)**	(312)	(47)	**(167)**	(312)	(47)
Change in non-cash working capital	**(688)**	5,646	-	**(4,142)**	(5,022)	(18)
Cash flow from operating activities: GAAP	**13,363**	18,807	(29)	**44,932**	63,323	(29)

NET EARNINGS

Was Delphi able to generate earnings in 2009?

For the three and twelve months ended December 31, 2009, Delphi recorded net earnings of $1.4 million ($0.02 per basic share) and a net loss of $8.0 million ($0.10 per basic share), respectively. Net earnings were affected by non-cash items such as depletion, depreciation and accretion, unrealized gains on risk management activities, stock-based compensation and future income taxes. These non-cash items represent the majority of the significant difference between funds from operations and net earnings.

NETBACK ANALYSIS

How do Delphi's netbacks achieved in 2009 compare to the prior year?

The Company's netbacks were lower than the previous year as the reduction in operating costs and royalties were more than offset by the decrease in realized sales price due to the significant drop in commodity prices. The operating netback and cash netback were higher than the cost of finding and developing reserves resulting in a positive recycle ratio.

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2009	2008	% Change	**2009**	2008	% Change
BARRELS OF OIL EQUIVALENT ($/BOE)						
Realized sales price	**41.50**	48.87	(15)	**39.50**	58.31	(32)
Royalties	**4.04**	8.53	(53)	**3.61**	11.12	(67)
Operating expenses	**6.76**	10.67	(37)	**9.08**	10.37	(12)
Transportation	**2.37**	3.76	(37)	**2.71**	2.99	(9)
OPERATING NETBACK	**28.33**	25.91	9	**24.10**	33.83	(29)
General and administrative expenses	**3.44**	2.35	46	**2.33**	2.06	13
Interest	**2.45**	1.73	42	**1.96**	2.20	(11)
CASH NETBACK	**22.44**	21.83	3	**19.81**	29.57	(33)
Unrealized loss (gain) on financial contracts	**0.37**	(0.91)	-	**0.85**	(0.26)	-
Stock-based compensation expense	**0.22**	0.42	(47)	**0.25**	0.43	(42)
Depletion, depreciation and accretion	**21.29**	25.17	(15)	**23.63**	26.59	(11)
Future income taxes (reduction)	**(1.63)**	(1.29)	26	**(1.68)**	0.62	-
NET EARNINGS (LOSS)	**2.19**	(1.56)	-	**(3.23)**	2.19	-

Delphi's production is predominantly natural gas and therefore Delphi's operating and cash netbacks are primarily driven by the price received for natural gas.

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

What has been the market activity in the Company's common shares?

At December 31, 2009, the Company had 101.2 million common shares outstanding (December 31, 2008 – 79.1 million). The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and twelve months ended December 31, 2009.

	Three Months Ended December 31, 2009	Twelve Months Ended December 31, 2009
Weighted Average Common Shares		
Basic	98,878	84,065
Diluted	[illegible]	[illegible]
Trading Statistics (1)		
High	[illegible]	[illegible]
Low	[illegible]	[illegible]
Average daily, volume	[illegible]	[illegible]

(1) *Trading statistics based on closing price*

How many common shares and stock options are currently outstanding?

As at March 16, 2010, the Company had 101.3 million common shares outstanding and 7.3 milllion stock options outstanding. The stock options have an average exercise price of $1.42 per share.

Sources and Uses of Funds

What have been the main sources and uses of funds in 2009?

In 2009, the Company paid down its bank debt by $10.3 million. The significant sources of funds were funds from operations, proceeds on dispositions and proceeds from the issue of equity. Total sources of funds were $93.9 million. Seventy percent of the sources of funds were directed at capital activities and 18 percent of funds were used to pay down bank debt.

	Three Months Ended December 31, 2009	Twelve Months Ended December 31, 2009
SOURCES:		
Funds from operations	[illegible]	[illegible]
Disposition of petroleum and natural gas properties	10,765	20,718
Issue of common shares	-	[illegible]
Issue of flow-through common shares	6,360	6,360
Exercise of stock options	11	43
Cash and cash equivalents	3,968	1,063
Change in non-cash working capital	7,724	-
	43,046	93,925
USES		
Capital expenditures	[illegible]	[illegible]
Acquisition of petroleum and natural gas properties	11,422	30,873
Share issue costs	[illegible]	[illegible]
Corporate acquisition costs	[illegible]	[illegible]
Expenditures on site restoration and reclamation	167	167
Repayment of acquired debt	6,750	6,750
Change in non-cash working capital	-	[illegible]
	28,146	83,625
Decrease in bank debt	(14,900)	(10,300)

Bank Debt plus Working Capital Deficiency (Net Debt)

How much bank debt was outstanding on December 31, 2009 and how does that amount compare to the previous year?

At December 31, 2009, the Company had $80.0 million outstanding in the form of bankers' acceptances and $1.1 million outstanding on its operating credit facility for total bank debt outstanding of $81.1 million, representing 65 percent of its credit facility. At December 31, 2009, the Company had a working capital deficiency of $11.4 million for total net debt of $92.5 million excluding the financial liability of $0.4 million relating to the unrealized loss on financial commodity contracts and the associated future income tax asset. Net debt levels were reduced by $16.7 million in 2009, a decrease of 15 percent, from $109.2 million at the end of the previous year. The Company's net debt to cash flow ratio on a 12 month trailing cash flow basis was 1.9:1 at the end of the year. On a fourth quarter annualized cash flow basis, the net debt to cash flow ratio was 1.6:1.

What are the Company's credit facilities and when is the next scheduled review of the borrowing base?

The Company has a $5.0 million operating facility and a $120.0 million revolving credit facility for a total of $125.0 million in credit. Upon completion of the semi-annual review and syndication undertaken by Delphi in the fall of 2009, the revolving credit facility of $125.0 million remains unchanged from the prior year. The next scheduled renewal of the Company's credit facilities will be in the spring of 2010 and will be determined based on the Company's year-end engineering report, the results of the winter drilling program and the lenders' view of future commodity prices and other factors.

What are the Company's forecast debt levels for the end of 2010?

In 2010, Delphi anticipates a field capital expenditure program equivalent to projected funds from operations with acquisitions being funded by equity and proceeds on the disposition of assets resulting in net debt levels between $95.0 and $100.0 million by the end of 2010. Growth in cash flow to approximately $60.0 million is expected to result in a net debt to cash flow ratio of approximately 1.7:1 by the end of 2010.

As in prior years, net debt is expected to increase in the first quarter of 2010 as a result of a winter capital program greater than cash flow with net debt being reduced in the second quarter as capital expenditures are expected to be minimal due to spring breakup. The significant excess cash flow generated in the second quarter will be applied against net debt. Capital expenditures for the second half of the year will be planned according to the cash flow generated and achieving net debt targets.

Contractual Obligations

Does the Company have any contractual obligations as of December 31, 2009 that will require funding in future years?

The Company is committed to future minimum payments for natural gas transmission and processing and operating leases on compression equipment. The Company also has a lease for office space in Calgary, Alberta.

The future minimum commitments over the next five years are as follows:

	2010	2011	2012	2013	2014
Gathering, processing and transmission	4,101	3,445	2,463	2,407	2, 407
Office and equipment lease	1,890	1,029	775	390	-
Total	5,991	4,474	3,238	2,797	2,407

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

Does Delphi have any outstanding guarantees on behalf of third parties or any off-balance sheet arrangements which could lead to liabilities in the future?

Delphi has not entered into any guarantees or off-balance sheet arrangements. Certain lease agreements entered into in the normal course of operations could be considered off-balance sheet arrangements, however, all leases are operating leases with lease payments charged to operating expenses or general and administrative expenses on a monthly basis according to the lease.

CRITICAL ACCOUNTING ESTIMATES

In preparing the Company's financial statements, is Delphi required to make estimates or assumptions about future events?

Delphi's financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Delphi's management reviews its estimates frequently; however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates, developing internal control systems and comparing past estimates to actual results.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion and the ceiling test are based on estimates of crude oil and natural gas reserves;
- Revenues, operating expenses and royalties for which accruals have been recorded for actual revenues and costs which have been earned or incurred but have not yet been received;
- Capital expenditures on projects that are in progress;
- Fair value of derivative contracts;
- Asset retirement obligations including estimates of future costs and the timing of the costs.

NEW ACCOUNTING STANDARDS

Were there any new accounting standards in 2009 which the Company has had to adopt and comply with?

Financial Instruments - Disclosure

During 2009, amendments were made to Section 3862, Financial Instruments – Disclosure which requires enhanced disclosures relating to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels.

Goodwill and Intangible Assets

Effective January 1, 2009, the Company adopted Section 3064, Goodwill and Intangible Assets, which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. The standard has been adopted prospectively and has no current affect on the Company's consolidated financial statements.

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian generally accepted accounting principles ("GAAP") for years beginning on or after January 1, 2011. Thus, effective January 1, 2011, the Company will be required to prepare its consolidated financial statements in accordance with IFRS, with appropriate comparative figures for the year ended December 31, 2010.

In July 2009, the International Accounting Standards Board ("IASB") approved IFRS transitional exemptions that will allow entities to allocate their oil and gas asset balance as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing properties. Under the exemption, exploration and evaluation assets are measured at the amount determined under an entity's previous GAAP. For assets in the development or production phases, the amount is also measured at the amount determined under an entity's previous GAAP; however, such values must be allocated to the underlying IFRS transitional assets on a pro-rata basis using either reserve values or reserve volumes as of the entity's IFRS transition date. This exemption will relieve entities from significant adjustments resulting from retrospective adoption of IFRS. The Company intends to utilize this exemption. The Company is also evaluating other first-time adoption exemptions and elections available upon initial transition that provide relief from retrospective application of IFRS.

The Company continues to assess the Canadian GAAP and IFRS differences as well as the effects of adoption and finalizing its conversion plan. The Company has determined that accounting for property, plant and equipment will be impacted by the conversion to IFRS. The Company currently follows full cost accounting as prescribed in Accounting Guideline ("AcG") 16, "Oil and Gas Accounting – Full Cost." Conversion from Canadian GAAP to IFRS may have an impact on how the Company accounts for costs pertaining to oil and gas activities, in particular those related to the pre-exploration and development phases. The conversion to IFRS will also result in other impacts, some of which may be significant in nature.

Ongoing assessments of other effects include stock-based compensation, provisions and asset retirement obligations. The Company also continues to perform assessments on less critical IFRS transition issues and has commenced analysis of IFRS financial statement presentation and disclosure requirements. These assessments will need to be further analyzed and evaluated throughout the implementation phase of the Company's project. At this time, the impact on the Company's financial position and results of operations is not reliably determinable or estimable.

The Company will continue to monitor any changes in the adoption of IFRS and will update its plan as necessary.

CORPORATE GOVERNANCE

Overview

The shareholders' interests are a critical factor in the operations and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the application of its corporate governance policies. Delphi's Board of Directors consists of five independent directors and two officers of the Company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's Management Information Circular and Annual Information Form for a listing of committees that oversee specific aspects of the Company's operating and financial strategy.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the issuer's management, including its President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Company's President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective and provide a reasonable level of assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified.

The Company notes that while it believes the disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures and internal controls will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met. There were no changes made to the disclosure controls and procedures or internal controls over financial reporting during the fourth quarter.

2010 OUTLOOK

What is the Company's overall strategy and plans for 2010 and beyond?

Corporate Strategy

Delphi emphasizes a full-cycle approach to its business and strives for internally generated development opportunities as a means of enhancing its production base and ultimately creating value for shareholders. Delphi's goal is to become a dominant natural gas developer and explorer focused in the deep basin of North West Alberta with approximately 25 percent of its production being crude oil and natural gas liquids. The objective is to develop an inventory of opportunities and undeveloped land base from which production and reserves can be added independent of acquisition activity. Currently, Delphi has identified over one hundred and fifty drilling locations, representing three to five years drilling inventory, in its core areas.

Capital Activities

With the continuing uncertainty in commodity prices and the economy, Delphi will fund its 2010 field capital program from internally generated cash flow from operations. Delphi has a planned 2010 field capital program ranging between $60.0 to $65.0 million with the objective of preserving the Company's financial flexibility and maintaining the flexibility to pursue and capture strategic growth opportunities attractively priced in this transaction-oriented environment.

The capital program for 2010 includes the drilling of up to 24 (17.6 net) wells with the majority of the capital allocated to the Company's three main areas, Bigstone, Hythe and Wapiti/Gold Creek.

Financial Strategy

The Company is well positioned to endure the current weak economic environment with high quality producing assets, increased exposure to light oil and liquids-rich natural gas opportunities, a large inventory of economic projects in numerous play types and a 2010 cash flow stream protected with 54 percent of the Company's current natural gas production hedged at an average price of $6.24 per mcf. Maintaining operational and financial flexibility, combined with expanding the Company's long-term growth inventory in a transaction-oriented environment, will be key drivers in the capital spending decision process for 2010 and beyond.

ADDITIONAL INFORMATION

Where is additional information about Delphi available?

Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com, at the Company's website at www.delphienergy.ca or by contacting the Company at Delphi Energy Corp. Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 or by e-mail at info@delphienergy.ca.

FORWARD LOOKING STATEMENTS This management discussion and analysis contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", may", "will", "should", believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.

More particularly and without limitation, this management discussion and analysis contains forward looking statements and information relating to the Company's risk management program, petroleum and natural gas production, future funds from operations, capital programs, commodity prices, costs and debt levels. The forward-looking statements and information are based on certain key expectations and assumptions made by Delphi, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the capital availability to undertake planned activities and the availability and cost of labour and services.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. Additional information on these and other factors that could affect the Company's operations or financial results are included in reports on file with the applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). The forward-looking statements and information contained in this press release are made as of the date hereof for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. Delphi undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

BASIS OF PRESENTATION. For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.

NON-GAAP MEASURES. The MD&A contains the terms "funds from operations", "funds from operations per share", "net debt", "cash operating costs" and "netbacks" which are not recognized measures under Canadian generally accepted accounting principles. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gain/(loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The Company has defined net debt as the sum of long term debt plus working capital excluding the current portion of future income taxes and risk management asset/liability. Net debt is used by management to monitor remaining availability under its credit facilities. Cash operating costs have been defined as the sum of operating expenses, transportation expenses, general and administrative expenses and interest costs.

Management's Report

The financial statements of Delphi Energy Corp. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management. External auditors appointed by the shareholders have conducted an independent examination of the Company's accounting records in order to express their opinion on the financial statements.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial and internal control. The Board exercises this responsibility through its Audit & Reserves Committee. The Audit & Reserves Committee has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the financial statements. The Audit & Reserves Committee has reported its findings to the Board of Directors who have approved the financial statements.

David Reid

David J. Reid
President and Chief Executive Officer

Brian P. Kohlhammer
Vice President Finance and Chief Financial Officer

Calgary, Canada
March 16, 2010

Auditors' Report

We have audited the consolidated balance sheets of Delphi Energy Corp. as at December 31, 2009 and 2008 and the consolidated statements of earnings/(loss), comprehensive income/(loss) and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 16, 2010

Consolidated Balance Sheets

AS AT DECEMBER 31

(Stated in thousands of dollars)	2009	2008
ASSETS		
Current assets		
Cash	–	1,029
Accounts receivable	15,630	14,572
Prepaid expenses and deposits	6,004	2,928
Future income taxes (Note 9)	112	
Risk management asset (Note 10)	–	[illegible]
	21,746	20,200
Property, plant and equipment (Note 5)	339,952	[illegible]
Total assets	361,698	364,538
LIABILITIES		
Current liabilities		
Outstanding cheques	139	105
Future income taxes (Note 9)	–	501
Accounts payable and accrued liabilities	32,933	36,211
Risk management liability (Note 10)	381	
	33,453	36,817
Long term debt (Note 6)	81,100	[illegible]
Future income taxes (Note 9)	23,917	[illegible]
Asset retirement obligations (Note 7)	11,818	9,730
	150,288	171,602
SHAREHOLDERS' EQUITY		
Share capital (Note 8)	200,055	[illegible]
Contributed surplus (Note 8)	11,048	[illegible]
Retained earnings	307	[illegible]
Total shareholders' equity	211,410	[illegible]
Total liabilities and shareholders' equity	361,698	364,538

Commitments (Note 11)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

Andrew E. Osis
Director

Lamont C. Tolley
Director

Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss) and Retained Earnings

YEARS ENDED DECEMBER 31

(Stated in thousands of dollars, except per share amounts)	2009	2008
REVENUE		
Petroleum and natural gas sales	94,618	135,124
Realized gain on risk management activities (Note 10)	3,546	278
	98,164	135,402
Royalties	(8,982)	(25,827)
Unrealized gain (loss) on risk management activities (Note 10)	(2,102)	608
	87,080	110,183
EXPENSES		
Operating	22,551	24,092
Transportation	6,739	6,944
General and administrative	5,788	4,779
Stock-based compensation (Note 8)	615	994
Interest	4,863	5,103
Depletion, depreciation and accretion	58,724	61,745
	99,280	103,657
Earnings (loss) before income taxes	(12,200)	6,526
TAXES (NOTE 9)		
Future income taxes (reduction)	(4,171)	1,432
	(4,171)	1,432
Net earnings (loss) and comprehensive income (loss)	(8,029)	5,094
Retained earnings, beginning of the year	8,336	3,242
Retained earnings, end of the year	307	8,336
Earnings (loss) per share (Note 8)		
Basic and diluted	(0.10)	0.07

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

YEARS ENDED DECEMBER 31

(Stated in thousands of dollars)	2009	2008
CASH FLOW FROM OPERATING ACTIVITIES		
Net earnings (loss)	(8,029)	5,094
Add non-cash items:		
Depletion, depreciation and accretion	[illegible]	[illegible]
Stock-based compensation	615	994
Unrealized loss (gain) on risk management activities	2,102	(608)
Future income taxes (reduction)	(4,171)	1,432
Expenditures on asset retirement obligations	(167)	(312)
Change in non-cash working capital (Note 12)	(4,142)	(5,022)
	44,932	63,323
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		
Issue of common shares, net of issue costs	[illegible]	[illegible]
Issue of flow-through common shares	6,360	12,002
Exercise of stock options	43	1,532
Repayment of acquired debt (Note 4)	(6,750)	
Increase (decrease) in long term debt	(10,300)	9,400
	4,330	38,925
CASH FLOW AVAILABLE FOR INVESTING ACTIVITIES	49,262	102,248
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		
Capital expenditures	(33,946)	(76,779)
Disposition of petroleum and natural gas properties	20,718	8,450
Acquisition of petroleum and natural gas properties	(30,873)	(38,120)
Corporate acquisition costs (Note 4)	(869)	-
Change in non-cash working capital (Note 12)	(5,355)	9,483
	(50,325)	(96,966)
Increase (decrease) in cash and cash equivalents	(1,063)	5,282
Cash and cash equivalents, beginning of the year	924	(4,358)
Cash and cash equivalents, end of the year	(139)	924
Cash and cash equivalents is comprised of:		
Cash	-	1,029
Outstanding cheques	(139)	(105)
	(139)	924
Interest paid	5,099	5,149

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

AS AT AND FOR THE YEARS ENDED DECEMBER 31, 2009 AND 2008

(All tabular amounts are stated in thousands of dollars, except per share amounts)

NOTE 1: DESCRIPTION OF BUSINESS

Delphi Energy Corp. ("the Company" or "Delphi") is incorporated under the Business Corporations Act (Alberta) and is a publicly-traded company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in North West Alberta.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, shareholders' equity, revenue and expenses and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results may differ from these estimates.

a) Principles of consolidation

The consolidated financial statements include the accounts of the Company, its wholly owned subsidiary and a partnership. All inter-entity transactions and balances have been eliminated.

(b) Petroleum and natural gas operations

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and the costs of production equipment.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20 percent or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted using the unit-of-production method based upon total proved reserves before royalties as determined by the Company's independent reserves engineers. Natural gas reserves and production are converted into equivalent barrels of oil at 6:1 based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from the depletion calculation. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The Company is required to perform a ceiling test at least annually to assess the carrying amount of oil and gas assets. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves using forecast prices and the lower of cost and market of unproved properties exceed the carrying amount of the petroleum and natural gas assets. If the carrying amount of the petroleum and natural gas assets is assessed to not be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk-free rate.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives of 20 percent to 50 percent.

(c) Joint operations

Certain of the Company's exploration, development and production activities are conducted jointly with others and accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(d) Goodwill

Goodwill, at the time of acquisition, represents the excess of the purchase price of a business over the fair value of the net assets acquired. Goodwill is assessed by the Company for impairment at least each year end. If the fair value of the business is less than the book value, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and is charged to earnings in the period of the impairment.

(e) Asset retirement obligations

The Company records the future cost associated with removal, site restoration and asset retirement costs of property, plant and equipment. The fair value of the liability for the Company's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using the Company's credit adjusted risk-free interest rate and the corresponding amount is recognized by increasing the carrying amount of property, plant and equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded. The associated asset retirement cost included in property, plant and equipment is amortized to earnings using the unit-of-production method over estimated proved reserves consistent with the depletion and depreciation of the underlying asset.

(f) Stock-based compensation

The Company records a compensation cost for all stock options granted to employees, directors or key consultants over the vesting period of the options based on the fair value method. The compensation cost is a charge to earnings or is capitalized as a cost of exploration and development activities with an offsetting increase to contributed surplus on the balance sheet. Consideration paid by employees, directors or key consultants upon exercise of the stock options and the amount previously recognized in contributed surplus are recorded as an increase to share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

(g) Future income taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, estimated future income tax assets and liabilities are determined based upon differences between the carrying amount as reported on the balance sheet and the tax basis of assets and liabilities and measured using substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change occurs. A valuation allowance is recognized against any future income tax assets if it is considered more likely than not that the asset will not be realized.

(h) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and share capital are adjusted by the estimated cost of the renounced tax deduction on the date of renouncement.

(i) Per share amounts

Basic per share amounts are computed by dividing the net earnings by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that would occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options, plus the unamortized stock-based compensation cost, would be used to buy back common shares at the average market price for the period. Anti-dilutive options or instruments are not included in the calculation.

(j) Financial instruments

i) Financial instruments – recognition and measurement

Financial instruments are classified into one of the following five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. All financial instruments, including derivatives and non-financial derivatives are measured in the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other financial liabilities which are measured at amortized cost determined using the effective interest rate method. The accounting for subsequent changes in fair value depends on initial classification, as follows: changes in fair value of held-for-trading financial assets are recognized in net earnings and changes in fair value of available-for-sale financial instruments are recorded in other comprehensive income until the investment is derecognized or impaired at which time the amounts are recorded in net earnings.

The Company classifies its cash as held-for-trading which is measured at fair value. Risk management asset/liability is classified as held-for-trading and is measured at fair value. Accounts receivable are classified as loans and receivables and are measured at amortized cost. Accounts payable and long term debt are classified as other financial liabilities and are measured at amortized cost.

ii) Derivatives

All derivative instruments, including embedded derivatives, are recorded on the balance sheet at fair value unless exempt from derivative accounting treatment if the normal purchase and sale election is made at the time the Company entered into the contract. All changes in the fair value of derivative instruments are recorded in earnings unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income. The Company has a risk management program whereby the commodity price associated with a portion of its future production is fixed in order to mitigate cash flow volatility resulting from fluctuating commodity prices. The Company sells forward a portion of its future production by entering into a combination of fixed price physical sale contracts with customers and fixed price financial contracts with financial counterparties. The Company has elected not to use hedge accounting on its fixed price contracts with financial counterparties resulting in all changes in fair value being recorded in the statement of earnings. The Company has elected to account for its physical commodity sales contracts which were entered into and continue to be held for the purpose of delivery of production in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives. Physical commodity sale contracts based in United States dollars include an embedded derivative associated with the foreign exchange rate. Due to this embedded derivative, the changes in the fair value of these contracts are included in the statement of earnings.

iii) Other comprehensive income

The Company includes a statement of comprehensive income, which is comprised of net earnings and other comprehensive income which, for the Company, relates to changes in gains or losses on derivatives designated as cash flow hedges. The Company has combined this statement with the statement of earnings.

iv) Transaction costs

Transaction costs attributable to financial instruments classified as other than held-for-trading are included in the recognized amount of the related financial instrument and recognized over the term of the resulting financial instrument using the effective interest rate method.

(k) Measurement uncertainty

The amounts recorded for depletion and depreciation of property, plant and equipment are based upon estimates of proved petroleum and natural gas reserves, production rates, commodity prices and future costs. The ceiling test is based upon estimates of proved and, if applicable, probable reserves, production rates, petroleum and natural gas prices, future costs and other assumptions. The asset retirement obligations are based upon future costs, expected inflation rates and other assumptions. The amounts for stock-based compensation are based on estimates of risk-free interest rates, expected lives and volatility. The fair value estimates for derivatives are based on expected future natural gas prices and volatility in those prices. Future income taxes are based on estimates as to timing of the reversal of temporary differences at tax rates substantively enacted in those years. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes to estimates in future periods could be material.

(l) Cash and cash equivalents

The Company considers deposits in banks less outstanding cheques as cash and cash equivalents.

(m) Revenue recognition

Petroleum and natural gas sales are recognized in earnings when the title and risks pass from the Company to its customer.

(n) Comparative figures

Certain comparative figures have been reclassified to conform with the current year's presentation.

NOTE 3: NEW ACCOUNTING STANDARDS

Financial Instruments - Disclosure

During 2009, amendments were made to Section 3862, Financial Instruments – Disclosure which requires enhanced disclosures relating to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Note 10 - Financial Instruments outlines the enhanced disclosures and liquidity risk disclosures.

Goodwill and Intangible Assets

Effective January 1, 2009, the Company adopted Section 3064, Goodwill and Intangible Assets, which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. The standard has been adopted prospectively and has no current affect on the Company's consolidated financial statements.

International Financial Reporting Standards

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian generally accepted accounting principles ("GAAP") for years beginning on or after January 1, 2011. Thus, effective January 1, 2011, the Company will be required to prepare its consolidated financial statements in accordance with IFRS, with appropriate comparative figures for the year ended December 31, 2010.

In July 2009, the International Accounting Standards Board ("IASB") approved IFRS transitional exemptions that will allow entities to allocate their oil and gas asset balance as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing properties. Under the exemption, exploration and evaluation assets are measured at the amount determined under an entity's previous GAAP. For assets in the development or production phases, the amount is also measured at the amount determined under an entity's previous GAAP; however, such values must be allocated to the underlying IFRS transitional assets on a pro-rata basis using either reserve values or reserve volumes as of the entity's IFRS transition date. This exemption will relieve entities from significant adjustments resulting from retrospective adoption of IFRS. The Company intends to utilize this exemption. The Company is also evaluating other first-time adoption exemptions and elections available upon initial transition that provide relief from retrospective application of IFRS.

The Company continues to assess the Canadian GAAP and IFRS differences as well as the effects of adoption and finalizing its conversion plan. The Company has determined that accounting for property, plant and equipment will be impacted by the conversion to IFRS. The Company currently follows full cost accounting as prescribed in Accounting Guideline ("AcG") 16, "Oil and Gas Accounting – Full Cost." Conversion from Canadian GAAP to IFRS may have an impact on how the Company accounts for costs pertaining to oil and gas activities, in particular those related to the pre-exploration and development phases. The conversion to IFRS will also result in other impacts, some of which may be significant in nature.

Ongoing assessments of other effects include provisions, stock-based compensation and asset retirement obligations. The Company also continues to perform assessments on less critical IFRS transition issues and has commenced analysis of IFRS financial statement presentation and disclosure requirements. These assessments will need to be further analyzed and evaluated throughout the implementation phase of the Company's project. At this time, the impact on the Company's financial position and results of operations is not reliably determinable or estimable.

The Company will continue to monitor any changes in the adoption of IFRS and will update its plan as necessary.

NOTE 4: CORPORATE ACQUISITION

During the fourth quarter of 2009, the Company acquired all of the issued and outstanding shares of Fairmount Energy Inc. ("Fairmount"), a publicly-traded company involved in the exploration for, development and production of crude oil and natural gas primarily in North West Alberta, for share consideration of 0.3571 of a share of the Company for each share of Fairmount. The aggregate purchase price of $6.4 million was paid for by issuing 5,834,974 common shares of the Company. The common shares issued by the Company were valued at $1.09 per share, representing the weighted average closing price of the Company's shares around the date of announcing the acquisition. The transaction was accounted for using the purchase method. The consolidated accounts of the Company include the results of Fairmount since October 8, 2009, the date the Company acquired control of Fairmount.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition.

PURCHASE PRICE	
Share consideration	6,360
Corporate acquisition costs	869
	7,229
ALLOCATED	
Petroleum and natural gas properties	7,112
Future income tax asset	9,179
Working capital	(2,035)
Bank debt	(6,750)
Asset retirement obligation	(277)
	7,229

NOTE 5: PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2009	*Cost*	*Accumulated depletion and depreciation*	*Net book value*
Petroleum and natural gas properties	448,619	218,505	230,114
Production equipment	[illegible]	[illegible]	[illegible]
Furniture, fixtures and office equipment	1,277	705	572
	593,709	253,757	339,952

As at December 31, 2008	*Cost*	*Accumulated depletion and depreciation*	*Net book value*
Net book value			
Petroleum and natural gas properties	406,455	168,124	238,331
Production equipment	132,887	27,150	105,737
Furniture, fixtures and office equipment	846	576	270
	540,188	195,850	344,338

For the year ended December 31, 2009, the Company capitalized \$4.2 million (December 31, 2008 - \$3.3 million) of general and administrative costs directly related to exploration and development activities.

As at December 31, 2009, costs in the amount of \$4.2 million (December 31, 2008 - \$3.4 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of \$51.3 million (December 31, 2008 - \$46.7 million) have been included in costs subject to depletion. All costs of unproved properties have been capitalized. Ultimate recoverability of these costs will be dependent upon finding proved oil and natural gas reserves.

On August 31, 2009, the Company closed an acquisition of predominantly natural gas producing properties in the Wapiti/Gold Creek area of North West Alberta for cash consideration of \$19.3 million. Upon closing the acquisition, the Company immediately disposed of 40 percent of the acquired working interest in the properties for cash proceeds of \$7.9 million.

On November 3, 2009, the Company closed a transaction whereby the Company acquired natural gas and light oil assets and related infrastructure in its core area of Hythe in North West Alberta in exchange for the Company's non-core assets and related infrastructure in the Progress area of North West Alberta and consideration of \$10.0 million in cash.

On December 9, 2009, the Company closed an acquisition of natural gas properties adjacent to its Hythe area of North West Alberta for cash consideration of \$1.6 million.

During the year, the Company disposed of non-core minor working interest natural gas properties for cash proceeds of \$2.5 million and in December of 2009 closed a transaction whereby the Company sold its royalty interests on certain producing wells and a 5 percent gross overriding royalty interest on production from the Bigstone area of North West Alberta for cash proceeds of \$10.3 million.

The Company performed a ceiling test calculation at December 31, 2009 to assess the recoverable value of property, plant and equipment, which indicated no write down was required. The future commodity prices used in the ceiling test were based on the December 31, 2009 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The following table summarizes the future benchmark prices the Company used in the ceiling test.

	Natural Gas			Crude Oil			
	Henry Hub [illegible]	AECO Spot (CDN$/mmbtu)	Delphi Gas (CDN$/mcf)	West Texas Intermediate (US$/bbl)	Edmonton Light (CDN$/bbl)	Bow River Hardisty (CDN$/bbl)	Delphi Oil (CDN$/bbl)
2010	6.00	5.96	5.92	80.00	83.26	71.61	74.66
2011	[illegible]	6.79	6.81	83.00	86.42	72.59	77.01
2012	7.10	6.89	6.89	86.00	89.58	73.45	79.52
2013	[illegible]	6.95	6.96	89.00	92.74	74.19	81.76
2014	7.35	7.05	7.10	92.00	95.90	76.72	84.13
2015	7.50	7.16	7.24	93.84	97.84	78.27	85.20
2016	[illegible]	7.42	7.55	95.72	99.81	79.85	86.61
2017	[illegible]	7.95	8.10	97.64	101.83	81.46	88.02
2018	[illegible]	8.52	8.73	99.59	103.88	83.11	91.73
2019	[illegible]	8.59	8.93	101.58	105.98	84.78	96.74
Thereafter (1)	[illegible]	+2%/yr		+2%/yr	+2%/yr	+2%/yr	

(1) Percentage change of 2% represents the change in future prices each year and after 2019 to the end of the reserve life.

NOTE 6: LONG TERM DEBT

As at December 31	2009	2008
Prime-based loans	1,100	91,400
Bankers' acceptances	80,000	-
TOTAL DEBT	81,100	91,400

The Company has a revolving facility for $125.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility until May 31, 2010, the term-out date. The term-out date may be extended for a further 364 day period upon approval by the banks. Following the term-out date, the facilities would be available on a non-revolving basis for a one year term. The credit facility bears interest based on a sliding scale pricing grid tied to the Company's trailing debt to cash flow ratio: from a minimum of the bank's prime rate plus 2.0 percent to a maximum of the bank's prime rate plus 5.0 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 3.0 percent to a maximum of bankers' acceptances rate plus a stamping fee of 5.0 percent.

During 2009, the Company converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. The bankers' acceptances have terms ranging from 90 to 182 days and a weighted average effective interest rate of 4.9 percent over the term.

The facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from working interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations, over the next three to 20 years, is approximately $25.1 million (December 31, 2008 - $21.4 million). A credit-adjusted risk-free rate of 8.0 to 10.0 percent and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

As at December 31	*2009*	*2008*
BALANCE, BEGINNING OF THE YEAR	*9,730*	*7,183*
Liabilities incurred	[illegible]	[illegible]
Liabilities disposed	[illegible]	[illegible]
Liabilities acquired	[illegible]	[illegible]
Liabilities settled	*(167)*	[illegible]
Accretion expense	*817*	*650*
BALANCE, END OF THE YEAR	*11,818*	*9,730*

NOTE 8: SHARE CAPITAL

(a) Authorized

An unlimited number of common shares.

An unlimited number of preferred shares issuable in series.

(b) Common shares issued

	2009		*2008*	
As at December 31	***Outstanding shares (000's)***	***Amount***	*Outstanding shares (000's)*	*Amount*
BALANCE, BEGINNING OF THE YEAR	*79,067*	*174,995*	*68,070*	*148,898*
Issue of common shares	*13,200*	*16,500*	*6,316*	*18,001*
Issue of common shares - Fairmount (Note 4)	*5,835*	*6,360*	-	
Issue of flow-through common shares	*3,000*	*6,360*	*3,530*	*12,002*
Exercise of stock options	*64*	*43*	*1,151*	*1,532*
Allocated from contributed surplus	-	*23*	-	*745*
Share issue costs	-	*(1,523)*	-	*(2,010)*
Future tax effect of share issue costs	-	*405*	-	*585*
Tax benefit renounced to shareholders	-	*(3,108)*	-	*(4,758)*
BALANCE, END OF THE YEAR	*101,166*	*200,055*	*79,067*	*174,995*

On July 17, 2008, the Company issued 6.3 million common shares at a price of \$2.85 per share and 3.5 million flow-through common shares at \$3.40 per share for gross proceeds of \$30.0 million.

On September 30, 2009, the Company issued 13.2 million common shares at a price of \$1.25 per share for gross proceeds of \$16.5 million.

On November 16, 2009, the Company issued 3.0 million flow-through common shares at a price of \$2.12 per share for gross proceeds of \$6.4 million.

As at December 31, 2009, the Company has incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through common shares issued in 2008. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures by December 31, 2010 to satisfy the terms of the flow-through common shares issued in 2009.

(c) Stock options

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options up to ten percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry. Options granted prior to September 1, 2009 vested over a two-year period starting on the date of grant. Options granted on September 1, 2009 or later vest over a two-year period with one-third vesting six months after the date of grant and one-third on each of the first and second anniversary of the grant date. The exercise price of each option equals the five day weighted average of the market price of the Company's common shares, immediately preceding the date of the grant. As at December 31, 2009 there were 7.4 million options to purchase shares outstanding.

The following table summarizes the changes in the number of options outstanding and the weighted average share prices.

	2009		2008	
As at December 31	Outstanding options (000's)	Weighted average exercise price	Outstanding options (000's)	Weighted average exercise price
BALANCE, BEGINNING OF THE YEAR	4,731	1.75	5,481	1.60
Granted	3,017	0.83	615	2.23
Cancelled	-	-	(60)	1.55
Forfeited	(256)	1.31	(154)	1.56
Exercised	(64)	0.67	(1,151)	1.33
BALANCE, END OF THE YEAR	7,428	1.40	4,731	1.75
EXERCISABLE, END OF THE YEAR	5,245	1.58	2,938	1.72

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2009.

	Options outstanding			Options exercisable	
Range of exercise price	Outstanding options (000's)	Weighted average exercise price	Weighted average remaining term (years)	Exercisable (000's)	Weighted average exercise price
\$0.65 - \$0.97	1,957	0.66	4.2	662	0.67
\$0.98 - \$1.54	915	1.19	4.5	240	1.20
\$1.55 - \$1.72	3,826	1.67	2.9	3,751	1.67
\$1.73 - \$2.15	510	1.81	2.8	445	1.80
\$2.16 - \$3.34	220	3.18	3.5	147	3.18
TOTAL	7,428	1.40	3.4	5,245	1.58

(d) Stock-based compensation

The Company accounts for its stock-based compensation using the fair value method for all stock options. For the year ended December 31, 2009, Delphi recorded non-cash compensation expense of \$0.6 million (December 31, 2008 - \$1.0 million). The Company capitalized \$0.9 million (December 31, 2008 - \$1.1 million) of stock-based compensation directly related to exploration and development activities. The future income tax liability associated with the capitalized stock-based compensation in the amount of \$0.3 million (2008 - \$0.4 million) has also been capitalized for the year.

During the year ended December 31, 2009, the Company granted 3.0 million options. The fair values of all options granted during the year are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the year was $0.43 per option (December 31, 2008 - $1.13 per option). The assumptions used in the Black-Scholes model to determine fair value were as follows.

Years ended December 31	2009	2008
Risk-free interest rate (%)	2.1	4.6
Expected life (years)	5.0	5.0
Expected volatility (%)	61.4	[illegible]

(e) Contributed surplus

The following table outlines the changes in the contributed surplus balance.

As at December 31	2009	2008
BALANCE, BEGINNING OF THE YEAR	9,605	8,236
Stock-based compensation expensed	615	994
Stock-based compensation capitalized	851	1,120
Reclassification to common shares on exercise of stock options	(23)	(745)
BALANCE, END OF THE YEAR	11,048	9,605

(f) Net earnings (loss) per share

Net earnings (loss) per share has been based on the following weighted average common shares.

Years ended December 31	2009	2008
Basic	84,065	[illegible]
Diluted	84,065	74,024

The reconciling item between the basic and diluted weighted average common shares outstanding is stock options.

(g) Capital management

The Company considers share capital and net debt, being the sum of long term debt and current liabilities less current assets, as the components of capital to be managed.

The Company's objective in managing its capital is to ensure adequate and appropriate sources of capital are available to execute a capital investment program while maintaining a flexible overall capital structure. Maintaining a flexible capital structure is important due to the inherent risks in oil and gas operations and the volatility of commodity prices.

The Company manages its capital structure by keeping abreast of current and forecast economic conditions and commodity prices, particularly natural gas prices and the cost of oilfield services. Additionally, the Company establishes internal processes to monitor and estimate planned capital expenditures, forecast funds from operations and current and forecast debt levels.

The key measure used by the Company to evaluate its capital structure is the ratio of net debt to funds from operations, defined as cash flow from operating activities before expenditures on asset retirement obligations and change in non-cash working capital from operating activities. This ratio represents the time period required to repay the Company's net debt from funds generated from operations on the assumption there are no further capital expenditures incurred and funds from operations remain constant. The measure is often calculated on a historic annual basis and on an annualized most recent quarter basis to provide a more current view of the Company's capital structure.

At December 31, 2009 net debt, excluding risk management assets or liabilities and the associated future income taxes was $92.5 million and funds from operations was $49.2 million resulting in a net debt to funds from operations ratio of 1.9:1 times. On an annualized fourth quarter 2009 basis, funds from operations would be $56.9 million resulting in a net debt to funds from operations ratio of 1.6:1. The Company is focused on achieving its internal target range for this ratio of approximately 1.5 times.

The Company maintains an active risk management program as an integral part of its capital management strategy to mitigate the volatility in funds from operations resulting from fluctuating commodity prices. The net debt to funds from operations ratio is the key driver in determining whether to maintain or alter the capital structure. To alter the capital structure of the Company, consideration is given to the level of credit available under current banking facilities, the proceeds on disposition of properties, the amount of the planned capital expenditure program and the offering of new common share equity if available on acceptable terms.

NOTE 9: TAXES

(a) Expected income tax rate

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial income tax rates to the Company's earnings before income taxes.

The difference relates to the following items:

Years ended December 31	**2009**	2008
Earnings (loss) before income taxes	**(12,200)**	6,526
Statutory tax rate	**29.07%**	29.84%
Expected income tax expense (recovery)	**(3,547)**	1,946
Stock-based compensation	**178**	297
Reduction in future income tax rates	**(771)**	(882)
Other	**(31)**	71
Total income tax expense (recovery)	**(4,171)**	1,432

(b) Future income tax liability

The income tax effect of temporary differences that give rise to significant portions of the future income tax assets and liabilities are presented below:

As at December 31	**2009**	2008
Future income tax assets:		
Asset retirement obligations	**2,955**	2,441
Attributed Canadian Royalty Income	**362**	270
Non capital losses	**4,093**	1,894
Share issue costs	**998**	1,067
Risk management liability	**112**	-
Future income tax liabilities:		
Risk management asset	**-**	(501)
Property, plant and equipment	**(32,325)**	(39,327)
Net future income tax liability	**(23,805)**	(34,156)

Non-capital losses of $16.4 million expire in the year 2027.

NOTE 10: FINANCIAL INSTRUMENTS

(a) Risk management overview

The Company is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Risk management is ultimately established by the Board of Directors and is implemented and monitored by senior management. The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in funds from operations resulting from fluctuating commodity prices. The strategy is designed to take advantage of the upward swings in natural gas prices as a result of the changes in demand/supply fundamentals and/or the movement of significant financial assets invested in the natural gas market as a pure commodity investment.

(b) Fair value of financial assets and liabilities

The Company's financial instruments recognized on the balance sheet include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, long-term debt and the risk management asset or liability. The fair value of financial assets and liabilities that are included on the balance sheet, other than the risk management asset or liability, approximate their carrying amounts due to long-term debt being at a floating interest rate and all other financial assets and liabilities having a short term maturity.

The Company's financial derivative contracts for natural gas prices are transacted in active markets. The Company classifies the fair value of these contracts according to the following hierarchy based on the amount of observable inputs used to value the instrument.

> Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
>
> Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors which can be substantially observed or corroborated in the marketplace.
>
> Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The Company's financial derivative contracts have been assessed on the fair value hierarchy as outlined above. The natural gas pricing contracts are classified as Level 2. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level.

(c) Market risk

Market risk is the risk that future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency exchange rate risk, interest rate risk and commodity price risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company utilizes both financial derivatives and physical delivery contracts to manage market risks.

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for petroleum and natural gas are affected by changes in the exchange rate between the Canadian and United States dollar. The exchange rate could affect the values of certain contracts, however, this indirect influence cannot be accurately quantified. The Company had no foreign exchange rate swap or related financial contracts in place as at December 31, 2009.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest. If interest rates on prime-based loans had been 100 basis points lower with all other variables held constant, net earnings for the year ended December 31, 2009 would have been $0.2 million (2008 - $0.6 million) higher, due to lower interest expense.

Interest rate risk is partially mitigated through short-term fixed rate borrowings using bankers' acceptances.

The Company has also entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $40.0 million maturing on May 4, 2011. The bankers' acceptance rate on the transaction will increase in fixed monthly increments of 4.55 basis points for an average fixed rate over two years of 0.94 percent. The effective interest rate over the two year term on $40.0 million of bankers' acceptances will be 0.94 percent plus the applicable stamping fee according to the pricing grid for bankers' acceptances. The fair value of this contract at December 31, 2009 is a loss of $0.1 million.

Commodity price risk

Commodity price risk is the risk that the future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are affected not only by the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. The Company has a commodity price risk management program in place whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production by entering into a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The fair values of the forward contracts are subject to market risk from fluctuating commodity prices and foreign exchange rates. The Company's policy is to enter into commodity contracts to a maximum of 40 – 50 percent of current production volumes.

As at December 31, 2009, the Company had the following financial derivative contracts which were recorded at fair value on the balance sheet at a loss of $0.4 million (December 31, 2008 - gain of $1.7 million) with changes in fair value included in unrealized gain (loss) on risk management activities in the statement of earnings.

Time Period	*Commodity*	*Type of Contract*	*Quantity Contracted*	*Contract Price ($/unit)*
January 2010 – December 2010*	*Natural Gas*	*Financial*	*3,500 GJ/d*	*$7.40 Call*
January 2010 – December 2010	*Crude Oil*	*Financial*	*100 bbls/d*	*$86.40 fixed*
January 2010 – December 2010	*Crude Oil*	*Financial*	*100 bbls/d*	*$72.20 floor/$100.00 ceiling*
April 2010 – October 2010	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$5.53 fixed*
April 2010 – October 2010**	*Natural Gas*	*Financial*	*2,500 GJ/d*	*$4.75 Put*
January 2010 – March 2011	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$5.72 fixed*
January 2011 – December 2011**	*Natural Gas*	*Financial*	*2,500 GJ/d*	*$7.14 Call*

* *The 2010 call contract was executed in 2009 to obtain a $6.00 put in 2009 on a costless basis.*

** *The Company has acquired a natural gas put contract at $4.75 per gigajoule on 2,500 gigajoules per day for the period April 1, 2010 through October 31, 2010. This put was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $7.14 per gigajoule for the period January 1, 2011 through December 31, 2011.*

The Company has Canadian dollar physical sales contracts. The Canadian dollar physical sales contracts were entered into and continue to be held for the purpose of delivery of non-financial items as executory contracts and have not been recorded at fair value. As at December 31, 2009, the Company had the following physical sales contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
April 2009 – March 2010	Natural Gas	Physical	3,000 GJ/d	$7.52 fixed
April 2009 – March 2010	Natural Gas	Physical	[illegible]	[illegible]
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	[illegible]
November 2009 – March 2010	Natural Gas	Physical	[illegible]	[illegible]
November 2009 – March 2010	Natural Gas	Physical	[illegible]	[illegible]
January 2010 – December 2010*	Natural Gas	Physical	3,500 GJ/d	$7.15 Call
January 2010 – March 2011	Natural Gas	Physical	1,500 GJ/d	$5.74 fixed
April 2010 – December 2010	Natural Gas	Physical	[illegible]	[illegible]
April 2010 – December 2010	Natural Gas	Physical	[illegible]	[illegible]
April 2010 – March 2011	Natural Gas	Physical	3,000 GJ/d	$6.12 fixed
April 2010 – March 2011	Natural Gas	Physical	2,500 GJ/d	[illegible]
April 2011 – October 2011	Natural Gas	Physical	2,000 GJ/d	$5.66 fixed

* *The 2010 call contract was executed in 2009 to obtain a $6.00 put in 2009 on a costless basis.*

For the year ended December 31, 2009, the Canadian dollar physical contracts resulted in settlement gains of $19.2 million (December 31, 2008 loss - $0.1 million) that have been included in petroleum and natural gas sales. For the year ended December 31, 2009, the financial contracts and U.S. dollar based physical contracts resulted in gains of $3.5 million (December 31, 2008 gain - $0.3 million) that have been included in the statement of earnings as a realized gain on risk management activities. As at December 31, 2009, if natural gas prices had been higher by $0.10 per mcf, with all other variables held constant, the net change in the unrealized loss on risk management activities in the statement of earnings for the year would have been lower by approximately $0.4 million (December 31, 2008 – $0.1 million).

The Company entered into the following contracts subsequent to December 31, 2009:

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
February 2010 – March 2010	Natural Gas	Financial	[illegible]	[illegible]
February 2010 – March 2010	Natural Gas	Financial	[illegible]	[illegible]
April 2010 – October 2010	Natural Gas	Financial	1,500 GJ/d	$4.80 floor plus 50% >$4.80

(d) Credit risk

Credit risk represents the financial loss to the Company if counterparties to a financial instrument fail to meet their contractual obligations and arise principally from the Company's receivables from joint interest partners. All of the Company's accounts receivable are with customers and joint interest partners in the oil and gas industry and are subject to normal industry credit risks. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company attempts to mitigate the risk related to joint interest receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, partners are exposed to various industry and market risks that could result in non-collection. The Company does not typically obtain collateral from natural gas marketers or joint interest partners; however, the Company does have the ability to request pre-payment of certain major capital expenditures and withhold production from joint interest partners in the event of non-payment of amounts owing.

The carrying amount of cash and accounts receivable represents the maximum credit exposure. The Company does not consider an allowance for doubtful accounts is required as at December 31, 2009, however, bad debt expense of $20,136 was recorded during the year.

As at December 31, 2009 the Company's aged receivables are as follows.

As at December 31	2009
Current (less than 30 days)	12,604
Past due (31-90 days)	832
Past due (more than 90 days)	2,194
TOTAL	15,630

(e) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will have sufficient cash resources to meet its liabilities when they become due. The Company actively monitors the costs of its operations and capital expenditure program by preparing an annual budget, formally approved by the Board of Directors. On a monthly basis, internal reporting of actual results is compared to the budget in order to modify budget assumptions, if necessary, to ensure liquidity is maintained.

The Company requires sufficient cash to fund its operating costs and capital program that are designed to maintain or increase production and develop reserves, to acquire petroleum and natural gas assets and to satisfy debt obligations. The majority of capital spent will be funded through cash flow from operating activities. The Company enters into risk management contracts designed to improve risk-adjusted returns and to ensure adequate cash flow to fund the Company's capital program and maintain liquidity. The Company uses a combination of both financial and physical commodity price contracts. Contracts are initiated within the guidelines of the Company's risk management program and are not entered into for speculative purposes. The Company also has a 364 day revolving credit facility with a syndicate of Canadian chartered banks with a one year term-out provision.

The following are the contractual maturities of financial liabilities as at December 31, 2009.

Financial liabilities	< 1 Year	1 – 2 Years	3 – 5 Years	Thereafter
Outstanding cheques	139	-	-	-
Accounts payable and accrued liabilities	32,933	-	-	-
Risk management liability	381	-		
Long term debt – principal	-	81,100	-	-
Total	33,453	81,100	-	-

NOTE 11: COMMITMENTS

The Company is committed to future minimum payments for natural gas transmission and processing, operating leases on compression equipment and office space. Payments required under these commitments for each of the next five years are: 2010-$6.0 million; 2011-$4.5 million; 2012-$3.2 million; 2013-$2.8 million; 2014-$2.4 million.

NOTE 12: CHANGES IN NON-CASH WORKING CAPITAL ITEMS

Years ended December 31	**2009**	2008
Change in working capital item:		
Accounts receivable	**(550)**	(1,918)
Prepaid expenses and deposits	**(2,874)**	(176)
Accounts payable and accrued liabilities	**(6,073)**	6,555
Total change in non-cash working capital	**(9,497)**	4,461
Relating to:		
Operating activities	**(4,142)**	(5,022)
Investing activities	**(5,355)**	9,483
	(9,497)	4,461

Corporate Information

DIRECTORS

David J. Reid[1]
President and Chief Executive Officer
Delphi Energy Corp.

Tony Angelidis
Senior Vice President Exploration
Delphi Energy Corp.

Harry S. Campbell, Q.C.[2]
Partner
Burnet, Duckworth & Palmer LLP

Robert A. Lehodey, Q.C.[2]
Partner
Osler, Hoskin & Harcourt LLP

Stephen Mulherin
Partner
Polar Capital Corporation

Andrew E. Osis[1]
Chief Executive Officer and Director
Multiplied Media Corporation

David Sandmeyer
Independent Businessman

Lamont C. Tolley[1]
Independent Businessman

(1) Member of the Audit & Reserves Committee
(2) Member of the Corporate Governance and Compensation Committee

AUDITORS

KPMG LLP

LEGAL COUNSEL

Osler, Hoskin & Harcourt LLP

TRANSFER AGENT

Olympia Trust Company

OFFICERS

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Hugo H. Batteke
Vice President Operations

Rod A. Hume
Vice President Engineering

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The Bank of Nova Scotia
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INDEPENDENT ENGINEERS

GLJ Petroleum Consultants Ltd.

STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE

ABBREVIATIONS

bbls .... barrels
bbls/d .... barrels per day
mbbls .... thousand barrels
mcf .... thousand cubic feet
mcf/d .... thousand cubic feet per day
mmcf .... million cubic feet
mmcf/d .... million cubic feet per day
NGL .... natural gas liquids
bcf .... billion cubic feet
boe .... barrels of oil equivalent (6 mcf:1 bbl)
boe/d .... barrels of oil equivalent per day
mmboe .... million barrels of oil equivalent

Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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